STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Illinois Power Company	:	
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Proposed general increase in natural gas rates.	:	**04-0476**
	:	

ORDER

DATED: May 17, 2005

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By the Commission:

I. PROCEDURAL HISTORY

On June 25, 2004, Illinois Power Company ("Illinois Power," "AmerenIP" or "IP") filed its Ill. C. C. No. 32, 10th Revised Sheet No. 1, 2nd Revised Sheet No. 2, 6th Revised Sheet No. 3, 3rd Revised Sheet No. 4, 3rd Revised Sheet No. 5, Original Sheet No. 5.1, Original Sheet No. 5.2, Original Sheet No. 5.3, 3rd Revised Sheet No. 11, 3rd Revised Sheet No. 12, 3rd Revised Sheet No. 13, 4th Revised Sheet No. 14, 3rd Revised Sheet No. 15, 2nd Revised Sheet No. 15.1, 5th Revised Sheet No. 16, 5th Revised Sheet No. 17, 4th Revised Sheet No. 18, 5th Revised Sheet No. 19, 6th Revised Sheet No. 20, 6th Revised Sheet No. 21, 4th Revised Sheet No. 21.1, 5th Revised Sheet No. 21.2, 1st Revised Sheet No. 21.3, 3rd Revised Sheet No. 23, 4th Revised Sheet No. 29, 6th Revised Sheet No. 43, 4th Revised Sheet No. 46, 3rd Revised Sheet No. 47, 4th Revised Sheet No. 48, 2nd Revised Sheet No. 49, 2nd Revised Sheet No. 49.1 and Ill. C. C. No. 34, 2nd Revised Sheet No. 1, 1st Revised Sheet No. 2, 2nd Revised Sheet No. 3, 2nd Revised Sheet No. 4, 1st Revised Sheet No. 4.1, 1st Revised Sheet No. 5, 1st Revised Sheet No. 6, 1st Revised Sheet No. 7, 1st Revised Sheet No. 9, and 1st Revised Sheet No. 10, hereinafter referred to as "Filed Rate Schedule Sheets", in which it proposed a general increase in natural gas rates, to be effective August 9, 2004. The filing of the Filed Rate Schedule Sheets was accompanied by prepared testimony and other exhibits and schedules and work papers pursuant to 83 Illinois Administrative Code Part 285.

Notice of IP's filing was published in newspapers of general circulation throughout IP's gas service area in accordance with the requirements of Section 9-201(a) of the Public Utilities Act ("Act"), 220 ILCS 5/9-201(a), and the provisions of 83 Ill. Adm. Code 255. The Commission entered a Suspension Order on July 21, 2004, and a Resuspension Order on November 10, 2004.

By letter dated July 19, 2004, from the Administrative Law Judge ("ALJ") assigned to the proceeding, IP was notified of certain deficiencies in its filing of schedules and work papers in accordance with 83 Ill. Administrative Code Part 285, Standard Filing Requirements for Electric, Gas, Telephone, Water and Sewer Utilities in Filing for an Increase in Rates. The deficiency letter required IP to provide various revised and additional schedules or an explanation as to why certain schedules need not be provided. Information responsive to the deficiency letter was timely provided by IP. There are no outstanding deficiencies and IP has complied with all other Standard Filing Requirements for gas utilities in connection with this proceeding.

Petitions to intervene were filed by A.E. Staley Manufacturing Company, Archer-Daniels-Midland Company, Caterpillar, Inc. and TeePak, LLC, as the Illinois Industrial Energy Consumers (collectively "IIEC"); the Attorney General on behalf of the People of the State of Illinois ("AG"); Business Energy Alliance and Resources, L.L.C. ("BEAR"); Constellation NewEnergy-Gas Division, LLC ("CNE-Gas"); the Citizens Utility Board ("CUB"); Central Illinois Public Service Company ("CIPS"); Central Illinois Light Company ("CILCO"); and Dynegy Inc. ("Dynegy"). All of the foregoing petitions to intervene were granted by the ALJ. Subsequently, CIPS and CILCO withdrew their interventions.

Pursuant to notice duly given in accordance with the Act and the rules and regulations of the Commission, a prehearing conference was held in this matter before a duly authorized ALJ of the Commission at its offices in Springfield, Illinois, on August 5, 2004. Ten days prior, notice of the prehearing conference was provided by the Chief Clerk of the Commission to municipalities in IP's gas service area in accordance with the requirements of Section 10-108 of the Act (220 ILCS 5/10-108). Evidentiary hearings were held at the Commission's offices in Springfield on January 20 and 21, 2005. Appearances were entered at the prehearing conference or at one or more of the evidentiary hearings by counsel on behalf of IP, IIEC, AG, BEAR, CNE-Gas, CUB, CIPS, CILCO, Dynegy and the Staff of the Commission ("Staff"). On April 15, 2005, the record was marked "Heard and Taken" by the ALJ.

The following witnesses submitted testimony on behalf of IP: Frank A. Starbody, Peggy E. Carter, Daniel L. Mortland, Kathleen C. McShane, Karen R. Althoff, Ronald D. Pate, Leonard M. Jones, Brian W. Blackburn, Patricia K. Spinner, Michael J. Adams, Dr. Ronald E. White, H. Gene Eagle, Kevin D. Shipp, Wayne G. Hood and Curtis D. Kemppainen, W. Chris Olsen, Dottie R. Anderson, Timothy L. Hower, Charles Mannix, Robert C. Porter and Lee R. Nickloy.

The following witnesses submitted testimony on behalf of Staff: Scott A. Struck, Burma C. Jones, Bonita A. Pearce, Janis Freetly, Michael McNally, Peter Lazare, Eric Lounsberry, Charles C. S. Iannello and Dianna Hathhorn.

The following witnesses submitted testimony on behalf of intervenors: David J. Effron, on behalf of the AG and CUB; Lee Smith on behalf of BEAR; Juliana Claussen and Troy Monroe on behalf of CNE-Gas; Christopher C. Thomas on behalf of CUB; and John W. Mallinckrodt and Dr. Alan Rosenberg on behalf of IIEC.

On January 20, 2005, during the evidentiary hearings, Staff filed a document captioned "Stipulation Concerning Resolution of Certain Revenue Requirements Issues" that was entered into between IP and Staff (the "Stipulation"). The Stipulation states that AmerenIP and Staff stipulate that certain then-outstanding revenue requirements issues shall be resolved as set forth in the Stipulation. The Stipulation covers the resolution of a number of rate base and operating expense issues and the issues of capital structure, cost rates for long-term debt, transitional funding trust notes and preferred stock, cost of common equity and overall rate of return. Taken in conjunction with the parties' acceptance at earlier stages of the proceeding of other proposed adjustments to rate base and operating revenues and expenses, resolution of issues in accordance with the Stipulation would resolve all revenue requirements issues in this proceeding with the exception of the Hillsboro Storage Field Base Gas Inventory and the Hillsboro Storage Field Used and Useful adjustment which are addressed in Sections III.C and III.D, respectively, of this Order. Appendix A to the Stipulation showed the development of the overall revenue requirement and base rate increase assuming Staff's positions on the two aforementioned Hillsboro Storage Field issues are adopted, and Appendix B to the Stipulation showed the development of the overall revenue requirement and base rate increase under the assumption that IP's positions on the aforementioned Hillsboro Storage Field issues are adopted.

In addition, on February 9, 2005, IP and Staff entered into and filed a "Stipulation Concerning Resolution of Certain Tariff and Rate Related Issues" (the "Tariff Stipulation"). The Tariff Stipulation addressed resolution of issues relating to IP's proposed Critical Day Imbalance Charge, the provision of advanced metering and communications equipment to Service Classification ("SC") 76 customers and the offering of this equipment to other non-residential customers on an optional basis, the fees and charges to be assessed by IP for the Electronic Metering Index and for the advanced communications equipment, including an exit fee to be charged to customers electing the optional service but then dropping it less than six years thereafter, and certain related tariff language. All of the matters addressed in the Tariff Stipulation are discussed more fully later in this Order.

Both the Stipulation and the Tariff Stipulation state that IP and Staff acknowledge that each of the stipulated resolutions of issues listed in the Stipulation and the Tariff Stipulation (the "Stipulated Resolutions") is supported by the record in this docket but that based on the record, the Commission could have reached a different determination for each of the Stipulated Resolutions. The Stipulation and the Tariff Stipulation further state that IP and Staff each acknowledges that it is accepting the Stipulated Resolutions for purposes of this docket in order to reduce and simplify the issues in this proceeding, conserve resources, and reduce uncertainty. The Stipulation and the Tariff Stipulation state that, accordingly, IP and Staff stipulate that neither of them will treat any of the Stipulated Resolutions as precedential for future cases, and that neither of them will argue, in any future cases, that the same or a similar issue to any of the Stipulated Resolutions should be decided by the Commission in the same manner set forth in the Stipulation or the Tariff Stipulation on the grounds that the issue was resolved in such manner in this docket or that IP or Staff agreed to such resolution in this docket. The Stipulation and the Tariff Stipulation further states that IP and Staff stipulate that they will request that the Commission's Order in this docket contain a statement that none of the Stipulated Resolutions shall be considered precedential for future cases. Finally, the Stipulation and the Tariff Stipulation each state that it shall not preclude IP, Staff or any other party from arguing in a future case that the same or a similar issue to any of the Stipulated Resolutions should be resolved in the same manner as set forth in the Stipulation or the Tariff Stipulation, on any grounds other than that it was resolved in such manner in this docket or that AmerenIP or Staff agreed to such resolution in this docket.

At the hearing held on January 20, 2005, in this docket, the ALJ inquired on the record if any party had any objection to the Stipulation. No party stated that it had any objection to the Stipulation. Additionally, subsequent to the filing of the Tariff Stipulation by AmerenIP and Staff, no other party indicated any objection to the Tariff Stipulation.

The Commission accepts the Stipulated Resolutions as set forth in the Stipulation and in Appendices A and B thereto, and, as shown in further detail in Sections III.A, V.A and VI of this Order, below, has incorporated the Stipulated Resolutions into the determination of the overall gas utility revenue requirement for AmerenIP in this proceeding. Similarly, the Commission accepts the Stipulated Resolutions as set forth in the Tariff Stipulations and, as shown in Section VII.G of this Order, below, has incorporated the Stipulated Resolutions set forth in the Tariff Stipulation into the determination of certain tariff issues in this proceeding. None of the Stipulated Resolutions in either the Stipulation or the Tariff Stipulation shall be considered precedential for future cases; however, this shall not preclude AmerenIP, Staff or any other party from arguing in a future case that the same or a similar issue to any of the Stipulated Resolutions should be resolved in the same manner as set forth in the Stipulation or the Tariff Stipulation, on any grounds other than that the issue was resolved in such manner in this docket or that IP or Staff agreed to such resolution in this docket. In the discussion of Uncontested Adjustments to rate base, operating revenues and expenses and cost of capital and rate of return in Sections III.A, V.A and VI, below, this Order identifies each such adjustment that is a Stipulated Resolution. Similarly, in the discussion of transportation-related issues in Section VII.G of this Order, the Commission identifies each resolved issue that is a Stipulated Resolution from the Tariff Stipulation.

The Commission notes that on September 30, 2004, during the course of this proceeding, IP was acquired by Ameren Corporation ("Ameren"). IP was formerly owned by Dynegy. The acquisition of IP by Ameren was approved by the Commission in Docket 04-0294 (Order issued September 22, 2004). Certain of the adjustments to rate base, operating expenses and cost of capital adopted for purposes of this proceeding, and the resolution of certain other issues herein, are the result of or otherwise reflect the acquisition of IP by Ameren from Dynegy.

Initial briefs were filed by IP, Staff, BEAR, IIEC, CUB/AG, and Dynegy. Reply briefs were filed by IP, Staff, BEAR, IIEC, and Dynegy. An ALJ's proposed order was served on the parties. Briefs on exceptions were filed by IP, Staff, BEAR and IIEC, and briefs in reply to exceptions were filed by IP, Staff, IIEC and Dynegy. All exceptions and replies to exceptions have been duly considered by the Commission.

II. TEST YEAR

For the test year in this proceeding, IP selected a historical test year consisting of the 2003 calendar year ended December 31, 2003, with pro forma adjustments. No party objected to the test year selected by IP. The pro forma adjustments adopted for purposes of this proceeding are identified in Sections III, V and VI of this Order.

III. RATE BASE

Illinois Power's proposed rate base, as presented in its direct case filing, included both original cost less accumulated depreciation of gas utility plant in service at December 31, 2003, and original cost less accumulated depreciation of general and intangible plant allocated to the gas utility pursuant to an asset separation study performed by IP witness Adams of Navigant Consulting. IP's proposed rate base also included a number of adjustments to actual per-books balances at December 31, 2003. Some of these adjustments were objected to by other parties while a number of these adjustments were not objected to by other parties. Additional adjustments to rate base were proposed by Staff and/or the AG and CUB ("AG/CUB") and were accepted by IP. During the course of the case, certain of the proposed adjustments to rate base were modified based on updated information. Finally, as discussed in Section I of this Order, above, IP and Staff stipulated to the resolution of certain proposed adjustments to rate base as set forth in the Stipulation, and no other party objected to these Stipulated Resolutions. The uncontested or agreed adjustments to rate base that are being adopted for purposes of this Order are discussed in Section III.A below. The two remaining contested rate base issues, relating to the Hillsboro Storage Field Base Gas Inventory and the Hillsboro Storage Field Used and Useful status, are addressed below.

A. Uncontested Adjustments to Rate Base

1. Depreciation Reserve Attributable to Contributions in Aid of Construction

The rate base incorporates the reserve for depreciation attributable to contributions in aid of construction that were recorded prior to 1984, at which time the Commission revised the Uniform System of Accounts ("USOA") to transfer the balance in Account 271, Contributions in Aid of Construction, to Account 101, Utility plant in service. (IP Ex. 2.1, p. 7)

2. Materials and Supplies and Working Gas Inventory

The rate base includes the 13-month averages for the test year of materials and supplies in Accounts 154 and 163 reduced by the 13-month average of accounts payable balances associated with materials and supplies inventories recorded in Account 232. The rate base also includes the 13-month averages of working gas inventory balances in Account 164.1 and gas in leased storage in Account 165. As recommended by Staff witness Burma Jones, the 13-month average for Account 165 reflects a reduction of $8,830,000 to rate base due to the removal of prepayments for purchased gas from the monthly balances used to calculate the 13-month average. (IP Ex. 2.36, p. 1, col. (C)) Additionally, as recommended by Staff witness Eric Lounsberry, the December 31, 2003 balance of gas in leased storage has been reduced by $3,071,000 due to a reduction in IP's leased storage service contract with Mississippi River Transmission Corporation. (IP Ex. 2.36, p. 1, col. (F))

3. Cash Working Capital

The rate base includes a cash working capital component that is based on a lead lag study prepared by IP witness Adams of Navigant Consulting based on test year 2003 data. The study originally prepared by Mr. Adams, as summarized in IP Exhibit 10.7, was subsequently adjusted (i) to remove the impacts of prepayments for gas purchases (Staff Ex. 9.0, Sch. 9.02), (ii) to remove the cash working capital requirement associated with deferred income taxes and investment tax credits, in connection with removal of ADIT and ADITC from the revenue requirement computation, and (iii) to correct certain computational errors. The final cash working capital component reducing rate base by approximately $1,073,000, was summarized on IP Exhibit 10.11.

4. Accumulated Deferred Income Taxes and Unamortized Investment Tax Credits

In connection with the acquisition of IP by Ameren, all of IP's accumulated deferred income taxes ("ADIT") and accumulated deferred investment tax credits ("ADITC") were eliminated as of September 30, 2004. Therefore, as of September 30, 2004, IP's balances of ADIT and ADITC were zero. Mr. Charles Mannix, Manager of Income Taxes for Ameren Services Company, testified that as a result, the rates to be set in this proceeding cannot be based on or reflect a reduction of rate base for any ADIT or ADITC that were recorded on IP's books as of and prior to September 30, 2004, or else IP would be in violation of the normalization provisions of the Internal Revenue Code, with the result that IP would no longer be entitled to claim accelerated depreciation for federal income tax purposes with respect to any depreciable assets subject to the jurisdiction of this Commission. (IP Ex. 18.1) The Stipulation provided that all ADIT at September 30, 2004, would be removed from the computation of rate base as presented by AmerenIP in IP Exhibit 2.55. In accordance with this Stipulated Resolution, all ADIT and ADITC recorded on IP's books as of and prior to September 30, 2004, have been removed in the computation of rate base for purposes of this case.

5. Customer Deposits

The rate base is reduced by the balance of customer deposits held by IP. IP originally used the December 31, 2003 balance of customer deposits for this purpose but subsequently agreed to use the average of 13 monthly balances for the test year as proposed by Staff witness Hathhorn. (IP Ex. 2.1, p. 9 and IP Ex. 2.36, p. 1, col. (E))

6. Customer Advances for Construction

The rate base reflects the balance of customer advances for construction recorded by IP at December 31, 2003. (IP Ex. 2.1, p. 9)

7. 2004 Capital Additions and Accumulated Depreciation on Additions

IP proposed to include capital additions to gas utility plant during 2004 in rate base. IP witness Pate described IP's Asset Management process for identifying, prioritizing and tracking progress associated with making capital investments (IP Ex. 6.1). Mr. Pate and IP rebuttal witness Eagle presented exhibits detailing IP's gas utility capital projects for 2004, the status of those projects and the expenditures on each project at several points in time. Based on application of the known and measurable standard required of pro forma adjustments by 83 Ill. Adm. Code 287.40, Staff witness Burma Jones recommended that the Commission should include in rate base only 2004 capital additions projects that had reached "scheduled" status in IP's Asset Management process by a specified date. IP agreed with this approach. In the Stipulation, Staff and IP stipulated that rate base should include the costs of 2004 capital additions projects that had reached "scheduled" status as of September 30, 2004, as presented in IP's rebuttal filing. (IP Ex. 12.4 and IP Ex. 2.36, p. 2, col. (K)) In addition, rate base is reduced by the amount of accumulated depreciation recorded for these 2004 capital additions, using the assumption that the capital additions are placed in service ratably throughout 2004. (IP Ex. 2.40 and IP Ex. 2.36, p. 2, col. (L))

8. Accumulated Depreciation on Embedded Plant in Service

In connection with inclusion of 2004 capital additions in rate base, IP agreed that rate base should also incorporate accumulated depreciation during 2004 on utility plant in service at the end of the test year, December 31, 2003 ("embedded plant in service") as proposed by AG/CUB witness Effron and Staff witness Jones. In the Stipulation, IP and Staff stipulated that rate base should reflect accumulated depreciation on embedded plant in service through September 30, 2004, as presented in IP's rebuttal testimony. (IP Ex. 2.37 and IP Ex. 2.36, p. 1, col. (H))

9. Hillsboro Storage Well Adjustment

During the course of this proceeding, IP determined that the cost recorded for drilling a new well at the Hillsboro Storage Field included certain expenditures that were capitalized but should have been expensed. Accordingly, IP adjusted rate base to reduce gas plant in service and accumulated depreciation to reflect the removal of these expenditures from plant in service. (IP Ex. 2.42 and IP Ex. 2.36, p. 2, col. (M))

10. Completed CWIP Not Transferred to Plant in Service at December 31, 2003

The rate base includes balances recorded on IP's books at December 31, 2003, as construction work in progress ("CWIP") for projects that had been completed and placed in service as of that date but which had not been transferred to utility plant in service accounts as of December 31, 2003. This adjustment also incorporates certain miscellaneous charges recorded for these projects subsequent to December 31, 2003. In addition, IP reduced rate base to reflect the retirement of various gas plant assets in connection with placing the CWIP projects into service. (IP Ex. 2.5; IP Ex. 6.7; IP Ex. 2.36, p. 3, col. (Q)) Finally, IP reduced rate base to reflect accumulated depreciation on these projects. (IP Ex. 2.40 and IP Ex. 2.36, p. 2, col. (P))

11. Small CWIP Projects

The rate base includes the balance at December 31, 2003, associated with small CWIP projects with durations of less than one month, on which no Allowance for Funds Used During Construction is charged. In addition, IP reduced rate base to reflect the retirement of gas plant assets in connection with placing the small CWIP projects into service. (IP Ex. 2.6 and IP Ex. 2.36, p. 3, col. (R)) Finally, IP reduced rate base to reflect accumulated depreciation on these small CWIP projects. (IP Ex. 2.40 and IP Ex. 2.36, p. 2, col. (P))

12. Adjustment for Capitalized Pension Expense

IP's adjustments to test year operating expenses included an adjustment for higher pension costs, as discussed in Section V.A of this Order. AG/CUB witness Effron noted that a portion of this adjustment to pension expense should be capitalized. IP agreed that a portion of the pension expense adjustment it initially proposed should be capitalized, and therefore that rate base should be correspondingly adjusted. In the Stipulation, IP and Staff stipulated that a 30% capitalization factor should be applied to the pension cost adjustment, as proposed by AG/CUB witness Effron and Staff witness Bonita Pearce.

13. Advanced Metering Equipment

As discussed in Section VIII.G of this Order, IP agreed to recommendations by Staff, IIEC and CNE-Gas that IP provide to transportation customers more timely information on daily gas deliveries, and to this end indicated that it would install additional metering and telecommunications equipment to facilitate providing daily usage information. AmerenIP witness Althoff presented IP Exhibit 5.9 showing a projected investment of $826,000 for this equipment. No party objected to the inclusion of this investment in rate base. (IP Ex. 2.36, p. 2, col. (O))

14. Retirement of River Bend Facility

IP reduced rate base to reflect the retirement in 2004 of its River Bend facility, which was still in service on December 31, 2003. This adjustment affected both utility plant in service and accumulated provision for depreciation. (IP Ex. 2.9 and IP Ex. 2.36, p. 3, col. (S))

15. Retirement of Computer Equipment

IP adjusted rate base to reflect the retirement in 2003 of certain mainframe computing equipment which was not recorded until 2004. This adjustment affects the portion of the original cost of this equipment and the related accumulated provision for depreciation that was allocated to the gas utility in the asset separation study. (IP Ex. 2.11 and IP Ex. 2.36, p. 3, col. (U))

16. Adjustment to General Plant Depreciation Reserve for Retirements

IP adjusted rate base for the accumulated provision for depreciation for general plant to reflect the impact of retirements of certain general plant assets prior to December 31, 2003, that had not yet been recorded on IP's books as of that date. (IP Ex. 2.12 and IP Ex. 2.36, p. 3, col. (V))

17. Incentive Compensation Costs and Stock Options Costs Capitalized

In the Stipulation, IP and Staff stipulated that incentive compensation costs (including the related payroll taxes (FICA)) and costs for employee stock options incurred during 2003 should be excluded from the computation of the revenue requirement. Because a portion of these costs were charged to construction and therefore capitalized, the adjustments to remove these costs reduce rate base as well.

18. Relocation Reimbursements

Staff witness Burma Jones disagreed with IP's accounting for payments that are received from governmental entities or other third parties as reimbursement when IP retires facilities and replaces or relocates them at the request of the governmental entity or third party to accommodate a project, such as construction of a highway. IP's practice has been to record such payments as a credit to Account 108, Accumulated Reserve for Depreciation of Utility Plant and to record the cost of the replacement facilities in Account 101, Utility Plant in Service. Staff witness Jones testified that relocation reimbursements are Contributions in Aid of Construction ("CIAC") and should be recorded in the manner prescribed by Gas Plant Instruction 2(D) of the Uniform System of Accounts, which requires that contributions be credited to the accounts charged with the cost of construction. Although IP witness Peggy Carter, in rebuttal, disagreed with Ms. Jones and defended IP's accounting for relocation reimbursements, she also proposed a compromise approach whereby the third-party reimbursement payment would be recorded as a credit to Account 108 up to the actual cost recorded for removal or retirement of the facilities being relocated, with the balance recorded as CIAC. Only the cost incurred for the replacement facilities in excess of the CIAC would be recorded as an addition to plant in service. In her rebuttal testimony, Staff witness Jones testified that this compromise approach would be acceptable. In the Stipulation, Staff and AmerenIP stipulated that the adjustment, and IP's future accounting for, relocation reimbursements would be based on this compromise approach. This adjustment impacts both plant in service and accumulated depreciation.

B. Hillsboro Storage Field

IP has had a storage field at Hillsboro since 1972; the field was substantially upgraded in the early 1990s. As a result of the upgrade, which was completed in 1993, the peak day deliverability of the Hillsboro Field was increased to 125,000 mcf/day and the expected working gas volume of the Field was increased to 7.6 bcf. Injections into the Field in connection with the upgrade increased the total inventory in the Field to 21.7 bcf, consisting of 14.1 bcf cushion gas and 7.6 bcf working gas. The expanded Hillsboro Field initially performed as expected. For the 1993-1994 through 1996-1997 heating seasons, the Field tested at a peak day deliverability value at or above 125,000 mcf/day in each season. Further, in the 1993-1994 winter, approximately 7.6 bcf of working gas was cycled (i.e., withdrawn for delivery to customers) from the Field. In subsequent winters, however, the amounts of working gas cycled from Hillsboro declined. Based on several years of declining annual deliverability, IP first observed that there could be a potential problem with the Hillsboro Field following the 1995-1996 winter withdrawal season.

During the ensuing several years, IP worked to determine the source of the declining deliverability at the Hillsboro Field. IP initially investigated whether there was a reservoir problem, i.e., whether gas injected into the Field was migrating from the underground structure or whether the shape of the structure was different than had been expected, with the result in either case being that gas injected into the Field was moving to areas where it could not be reached by the Field's withdrawal wells. IP had a vertical seismic profile and then a three-dimensional ("3-D") seismic profile of the Field prepared by outside consultants; these analyses resulted in the preliminary conclusion that approximately 3.5 bcf of gas had migrated to another underground structure to the northeast of the Hillsboro Field. Based on these results, in 2000 IP drilled a new well to the northeast of the Hillsboro Field where it was believed a sub-structure existed to which gas had migrated from the main reservoir. However, when the well was drilled, it was discovered that there was not a separate sub-structure in that area. Thereafter, IP conducted a number of additional analyses to determine if there was a reservoir problem, including conducting crosswell seismic surveys[1]; performing well stimulation

[1] A crosswell seismic survey is a high resolution process capable of resolving underground features much smaller than those visible with a 3-D surface seismic analysis.

treatments on a total of six of the wells at the Hillsboro Field[2]; performing additional neutron log analyses[3]; conducting flame ionization surveys[4]; analyzing whether gas leakage was occurring from plant piping or equipment back into the Field (none was discovered); and other analyses. These analyses continued into 2003.

While IP was investigating whether there was a reservoir problem with the Hillsboro Field, it was also investigating whether there were problems with the injection and withdrawal metering at the Field.[5] In August 1999, IP retained Peterson Engineering to conduct an audit of the metering at the Hillsboro Field. The Peterson audit identified two metering problems:

(1) Two new turbine injection meters installed at the Field were over-registering gas injections under certain operating conditions. When the compressors that were situated near the turbine meters were operating at 50% loadings, they caused the meters to over-spin, thereby recording a greater amount of gas than was in fact passing through the meters. The over-registration was determined to be 26% when the compressors were operating at 50% loadings. (When the compressors were operated at close to full loadings, however, only minimal over-registration occurred on the turbine meters.)

(2) The orifice opening on the orifice meter at the south withdrawal secondary run was smaller than the value that had been stamped on the equipment at the manufacturer's plant.[6] The orifice value stamped on the equipment was the same value that IP had ordered, but the size of the opening was actually smaller than the value stamped on the orifice plate. This meant that less gas was being withdrawn from the Field than had been believed,

[2]Well stimulation treatments consist of injecting chemicals through a well bore and into the reservoir to attempt to clean up barriers near the well bore that may be interfering with injections or withdrawals.

[3]A neutron log is a survey done inside a gas well that can determine the water-gas mix within a reservoir by measuring the hydrogen ion concentration; this information was used in analyzing (i) whether there was gas leakage from the reservoir formation (none was detected) and (ii) whether the thickness of the "gas bubble" within the reservoir was changing (it was determined that the gas bubble in the Hillsboro reservoir was thinning).

[4]Flame ionization tests are conducted at ground level to identify any migration of gas at the surface that would not be detected through neutron logs. No surface gas leakage was identified.

[5]The metering at the Hillsboro Storage Field consists of (i) the plant metering, at which all gas coming into the Field for injection is measured, and (ii) injection and withdrawal metering at each of the 14 inject/withdraw wells located throughout the Field, at which gas is actually injected into the Field and subsequently withdrawn for delivery to customers.

[6]The principal gas withdrawal facility into the south pipeline from the Hillsboro Field is the primary run. The secondary run, on which the orifice metering problem was found, only operates occasionally, during periods of high withdrawal flow rates.

because the (incorrect) size of the orifice opening is a value that is input into the programmable logic controller for the meter, which calculates the value of gas passing through the meter.

To correct the turbine metering measurement errors, IP changed its operating procedures to avoid the 25% and 50% compressor loading levels, since these were the compressor loading levels that caused the most significant over-registration on the turbine meters. Additionally, the static pressure sensing points for the turbine meters were relocated to improve their accuracy. These steps, which were recommended by Peterson Engineering, were implemented in May 2000. To correct the orifice metering problem, the correct, actual size of the orifice opening was input into the programmable logic controller so that it would correctly calculate the amount of gas passing through the meter.

These corrective actions taken in response to the Peterson Engineering audit largely mitigated the metering problems at the Hillsboro Field by the Spring of 2000; as a result, the actual injection measurement error occurred over the period 1994-1999. At the time the corrective actions were taken IP believed that the injection metering error and the orifice withdrawal metering error were approximately offsetting. Moreover, for the 1999-2000 winter season, based on testing results as well as the overall accumulated experience of reduced deliverability from the Hillsboro Field over the preceding several years, IP had reduced the expected peak deliverability rating from 125,000 mcf/day to 100,000 mcf/day.[7] IP continued to investigate the source of the Hillsboro Field deliverability problem as described earlier.

A volumetric analysis of the volume of gas in the Field in the Spring of 2002 indicated that there was approximately 5.5 bcf less gas in the Field than there had been in the Spring of 1993.[8] This analysis, along with a comparison of the gas injected as measured by the plant injection meters (the turbine meters) to the gas being injected as measured by meters at the individual injection wells, led to the conclusion that the turbine meters had been recording substantially more gas than had actually been injected into the Field over an extended time period, and that as a result the gas volumes in the Field had been substantially depleted as a consequence of the measurement errors. Further, the other analyses that IP had conducted to attempt to determine if there was a reservoir problem with the Hillsboro Field enabled IP to rule out the likelihood that the source of the gas depletion was a structural or geological problem.

C. Hillsboro Storage Field Gas Inventory Adjustment

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[7]The peak day deliverability rating of the Hillsboro Field has been subsequently restored to 125,000 mcf/day, prior to the 2003-2004 winter season. This deliverability has been confirmed by testing, and the peak day rating continues at 125,000 mcf/day for the 2004-2005 winter season

[8]The volumetric analysis uses data on the volume of the reservoir and gas-water saturation data from the neutron logs to develop an estimate of the gas volume actually in the reservoir.

1. Staff's Position

Staff argues that IP has not demonstrated that it should be allowed to include the replacement gas for its depleted recoverable base gas in rate base. Staff continues stating that but for the measurement errors, IP would not have used recoverable base gas to serve current load and the issue concerning the appropriateness of IP's proposed increase in the value of recoverable base gas would not exist. Staff believes that IP failed to maintain its system in such a manner so as to avoid such measurement errors and failed to discover and correct the malfunctioning equipment in a timely manner so as to minimize and eliminate such errors. Staff asserts that IP's failure to act in these regards resulted in the withdrawal of recoverable base gas to serve current load. Now IP seeks to replace that gas, place it in rate base at a higher value than the gas which it is replacing, and earn a return on it from ratepayers. Staff further asserts that the Company should not be rewarded for operating errors by increasing the value of recoverable base case included in rate base.

According to Staff, the methods used by IP to calculate its Hillsboro storage field measurement errors, the resulting actual gas inventory, the recoverable base gas withdrawal, and the injection amounts are simply too speculative and not sufficiently accurate to provide a reasonable basis for an adjustment to and recalculation of the value of recoverable base gas amounts.

Staff recommends that the Commission continue to use the previously existing base gas inventory value that the Company used prior to making any adjustments to the Hillsboro recoverable base gas inventory, and reject the Company's requested $10,367,838 increase.[9] Under Staff's recommendation, IP would not be rewarded and ratepayers would not be penalized for IP's metering errors. IP would lose the opportunity to earn a rate of return on the $10,367,838 increase in recoverable base gas, but would retain the ability to pass the cost of that gas through the PGA when it closes the Hillsboro Storage field.

Staff notes that the Company's initial brief focuses on the suitability of its estimate of the Hillsboro storage field measurement errors, the resulting actual gas inventory, the recoverable base gas withdrawal, and the injection amounts as an appropriate basis for its proposed adjustment to and recalculation of the value of recoverable base gas amounts.

[9] IP explains that because it made certain accounting entries in 1999, its pro forma adjustment to the value of its test year base gas inventory is only $1,908,000 instead of the $10,367,838 increase in base gas inventory since its last rate case. (IP IB, pp. 11-12) Although IP stops short of arguing that the proper amount of the adjustment is the $1.9 million test year adjustment instead of the $10.4 million change in value, its presentation in this regard is potentially confusing. Staff wants to make clear that the Company's internal accounting treatment has not been subject to prior commission review (having occurred subsequent to its last rate case). Thus, the cumulative adjustment of $10,367,838 is the proper amount subject to review in this docket.

a. Simulation Studies

Staff notes that IP indicated that the reservoir simulation studies conducted by its outside expert were state-of-the art techniques, regardless of the ultimate use to be made of the volume estimate (e.g. setting utility rates or some other purpose). Staff further notes that IP specifically indicated the basis for the reservoir simulation studies was that they were used by companies, financial institutions and countries for the basis for investing hundreds of millions of dollars.

However according to Staff, the issue at hand in the instant proceeding is not a situation involving the investment decisions of a company, financial institution, or a country, but rather involves the ratemaking treatment for base rates of a substantial measurement error that persisted for six years. Staff argues that the Commission is making ratemaking decisions that impact captive ratepayers who have no, or very little, choice about how IP manages its operations, and the Commission is charged with ensuring only just and reasonable rates are charged to those customers. Staff asserts that the Company has failed to provide any mention in the record of any instance where a reservoir simulation study formed the basis for setting “utility rates” or was used to determine the level of inventory shortfall that occurred as a result of massive measurement errors at a utility operated storage field. In fact according to Staff, the only record information that should be given any weight is IP’s admission that its inventory correction value is an estimate. Staff asserts that IP has failed to meet its burden in this case.

Staff asserts that IP has engaged several consultants to determine the cause and extent of the various problems with its Hillsboro Storage field. Staff notes that the Company indicated that it used outside consultants to conduct a vertical seismic profile (1997) and a three-dimensional seismic profile (1998) of the Hillsboro storage field and these consultants reached the conclusion that 3.5 Bcf of gas had migrated to another underground structure to the northeast of the Hillsboro storage field. Even though IP now qualifies the results of these seismic profiles as “preliminary”, the Company incurred the expense of drilling a new well to the northeast of the Hillsboro storage field (in November 2000) where it believed a sub-structure existed to which gas had migrated from the main reservoir. When IP drilled the well, it determined that there was not a separate substructure to the northeast of the main Hillsboro structure. These consultants had erred.

Staff states that IP now places its reliance upon Mr. Hower, who has worked as a consultant for IP, assisting with reservoir studies for both its Hillsboro and Shanghai Fields since 1992. Staff argues that despite Mr. Hower’s impressive resume, it is hard to ignore that Mr. Hower’s assistance with the storage fields parallels the time period during which IP was experiencing metering errors and declining deliverability at Hillsboro. Staff argues that if there is truly not a better, more reliable technique than the reservoir modeling analysis to determine the gas volumes in place at the Hillsboro Field then one is left to wonder why IP continues to rely upon the well chart analysis to corroborate the findings from the reservoir modeling. Moreover, according to Staff, IP cannot transfer its failure to develop a reliable method to resolve the measurement errors that occurred under its management to Staff or its ratepayers. Staff believes that the lack of an alternative measure should not, by default, result in an increase in the value of recoverable base gas for ratepayers.

Staff's original concerns about the use of the reservoir model to form the basis for an inventory correction amount remain. Staff has provided sound criticisms of IP's study. Staff asserts that IP's proposed value is just an estimate, the sheer size of the Hillsboro storage field (5,247 acres or 8.2 square miles) makes it extremely difficult to determine an exact value, and the limitation of the model (no matter how sophisticated) will not allow the Company to provided an estimate that is just and reasonable for setting rates. According to Staff, these concerns coupled with IP's past history regarding analyses performed by outside consultants supports Staff's conclusion that IP's proposed value to adjust the Hillsboro storage field's inventory value is not sufficiently reliable to result in just and reasonable rates and should be rejected.

b. Inventory Correction Amount

Staff notes that IP used three independent analyses -- reservoir simulation, volumetric analysis, and well chart integration -- to develop its position regarding the volume of the inventory depletion. IP states that it placed the greatest reliance on the reservoir modeling study and the least reliance on the well metering (well chart) analysis. According to Staff, however, IP inconsistently states that the well chart integration analyses support its reliance on the reservoir simulation. "[T]he well chart integration analyses, which produced correction factors much more consistent with the 5.8 Bcf shortfall estimate than with the shortfall estimate produced by the volumetric analysis helped confirm that the value produced by the reservoir simulation technique should be adopted." (IP IB, p. 26.) Staff notes that IP also stated: "...if IP had placed no reliance on the well chart analysis, its overall estimate of Hillsboro gas inventory depletion would not have changed." (IP IB, p. 21) Thus, although in the face of Staff's criticisms of the well chart analysis, IP distances itself from it, IP continues to rely upon the well chart analysis to bolster the claim that the results of the reservoir analysis are reliable. If IP cannot decide whether or not to support its own analysis, then the Commission should not place any reliance on IP's claims that its other analyses are accurate.

c. Recovery through the Company's PGA Clause

IP argues that Staff's position that the Company should seek recovery of the cost of the gas it seeks to treat as replacement base gas through the PGA is unfounded. (IP IB, pp. 27-28). First, to the extent that IP is referring to a return "of" its investment, the Company errs in its position that the $10,367,838 increase in recoverable base gas should be recovered through IP's base rates (i.e., as a rate base component), and not through its PGA. (IP IB, p. 28) *Recoverable* base gas is not a depreciable asset that is recovered through base rates. Only the *non-recoverable* base gas, which is depreciable, is recovered through base rates.

Staff agrees that Section 525.40(c) of the Commission's Rules (83 Ill. Adm. Code 525.40(c)) states as follows: "The cost of gas estimated to be withdrawn from storage during the base period shall be included in the Gas Charge(s)." (IP IB, p. 28) Presumably, at such time as the Company decides to close the storage field, it will deliver the recoverable base storage gas to customers and the cost of that gas, subject to normal prudency standards, will be passed through the PGA. This is the identical treatment as that which will be given to the $20,676,363 base gas inventory value that is not at issue in this proceeding.

The effect on the Company if it is not allowed to increase the value of its recoverable base gas in the instant proceeding by $10,367,838 is forfeiture of the rate of return on that dollar amount. Rate of return is a component of the revenue requirement on which base rates are set. Staff believes it would be unfair to set rates that transfer the responsibility for management errors at the Hillsboro storage field to the ratepayers (i.e., allow the Company to increase the inventory value of its recoverable base gas and compel ratepayers to give shareholders a return on that increase). Therefore, Staff recommends that the Commission reject the Company's request to increase the value of its recoverable base gas.

2. Illinois Power's Position

a. IP's Adjustments to the Hillsboro Gas Inventory Amounts

IP states that in 1999, based on the actual operating performance of the Hillsboro Field to that point, it made accounting entries to reflect the amount of gas believed to be in the Field at that time, based on then-available information. While the total amount of gas in the Field per IP's books was not changed, the total inventory was reallocated between working gas and base gas. Specifically, 3.6 bcf of gas with a book value of $8,460,000 was shifted from the working gas account to the recoverable base gas account. According to IP, this resulted in accounting balances of 17.7 bcf of non-recoverable and recoverable base gas and 4.0 bcf of working gas in the Field. Subsequently, based on its analysis completed in 2004 of the gas inventory depletion that had resulted from the injection metering error, IP reversed the 1999 accounting entries. According to IP, the analysis completed in 2004 determined that there had been an inventory depletion of 5.8 bcf, of which 1.8 bcf was recoverable base gas and 4.0 bcf was working gas. In other words, 1.8 bcf had been withdrawn from recoverable base gas and supplied to customers as a result of the injection measurement error, and needed to be restored. IP stated that reinjection of the depleted 1.8 bcf of base gas has been completed. IP re-priced the base gas inventory to reflect the withdrawals and reinjection, resulting in a total value for the base gas inventory of $31,044,200, which is $10,367,838 higher than the base gas value recorded in 1993 of $20,676,363. According to IP, however, since the $8,460,000 adjustment to base gas inventory recorded in 1999 was on IP's books and records at December 31, 2003, the amount of the pro forma rate base adjustment to test year balances proposed by IP is $1,908,000 (i.e., $10,368,000 minus $8,460,000).

b. IP's Development of the Amount by which the Hillsboro Gas Inventory had been Depleted

IP states that it determined the depleted gas inventory volumes at Hillsboro using three separate methods. IP further states that two of those studies were performed by a qualified outside consultant under IP's direction, and the third was prepared internally. It is IP's position that the resulting estimate of the gas inventory depletion and reinjection is reasonable, reliable and sufficiently accurate to be the basis for a rate base component. IP states that it used Reservoir Modeling and IP has collected or commissioned 3-D seismic data, core data, special core analyses studies, neutron logs, detailed petrophysical and geological interpretations, a 3-D geological model, and a numerical reservoir simulation model for the Field. IP asserts this is one of the most sophisticated analysis techniques available in estimating the volume of gas in place in the Hillsboro Field, and thus the amount of the inventory depletion and are state-of-the art techniques which adhere to standard, accepted industry practice for evaluating gas storage reservoirs and are used by gas storage operators throughout the world. IP further asserts these techniques are accepted by the Society of Petroleum Engineers ("SPE") and the Securities and Exchange Commission ("SEC"), who are responsible for outlining the standards used by the oil and gas industry in the assessment of hydrocarbon volumes, such as the amount of proved underground reserves.

IP describes the steps in the reservoir modeling analysis that was conducted to estimate the gas volumes in place at the Hillsboro Field that include constructing a detailed 3-D geological model for the Hillsboro gas reservoir. IP notes that the 3-D model was used to construct a reservoir simulation model for the Hillsboro Field. The model was calibrated against observation well pressures, shut-in field pressures, gas saturation data from neutron logs and gas-water contact levels. The model was then run using different injection rate schedules. IP determined that the case which provided the best match of simulation results to the actual measured data was the case that produced a total inventory volume in place of 16.8 bcf, or a variance (shortfall) of 5.8 bcf from the total inventory volume per IP's books.

IP notes the Staff expressed various concerns concerning the use of the reservoir simulation model. IP argues that the reservoir simulation model is routinely used to evaluate hydrocarbon reservoirs that are much larger than the Hillsboro reservoir and contain significantly fewer wells and that that reservoir simulation models are used throughout the industry to evaluate and optimize the performance of gas storage reservoirs and as a tool in realizing the full potential of underground storage fields in terms of volume and withdrawal rates, and in optimizing the design (including number of wells) and operation of underground storage facilities. IP argues that reservoir simulation modeling is appropriate for use in connection with an aquifer storage reservoir such as Hillsboro where there is uncertainty as to the amount of gas that has been injected over time and the objective is to determine the volumes of gas in place in the reservoir (and thus the amount of the inventory depletion) in light of this uncertainty.

IP argues that there is no basis for the implication that the development of storage field inventory or reserve estimates for financial reporting and public company investor disclosure purposes is somehow less important than the development of such information for use in setting regulated rates.

IP further argues that in practice, for many aquifer gas storage reservoirs there are uncertainties and the gas volume in place is not accurately known. (Such uncertainties can arise, for example, from gas leaks in wells and surface facilities or gas losses in the subsurface (migration off structure), as well as gas measurement errors. IP states that this is precisely why it is appropriate to use reservoir simulation techniques and methods like those used in the oil and gas production industry which face uncertainty as to the hydrocarbon volumes in place in a reservoir or production area. IP states that since it is undisputed that there was uncertainty as to the gas volumes in place at Hillsboro, the appropriate techniques to use to obtain the most accurate evaluation of the gas in place possible are the same techniques routinely used by the petroleum industry for the same purposes, namely, reservoir simulation techniques.

IP argues that the Hillsboro reservoir simulation model was constructed on a foundation of known, accurate data such as 3-D seismic, core data, special core analyses, petrophysical calculations and measurements of well and field data. IP further argues that the reservoir simulation model for the Hillsboro Field was not used to make predictions about the reservoir's future behavior once it is refilled, but rather, the reservoir model was used to determine the volumes of gas in the Field in 2004, in a situation of depleted inventory, which was done by modeling the performance of the Field in past years using a substantial base of known data, not by projecting the Field's performance in future years.

c. Volumetric Analysis

Illinois Power states that the second method it used, volumetric analysis which uses a detailed 3-D geological model, neutron logs to determine the gas saturation and location of the gas-water contact, and with an interpretation of the top of the reservoir and estimates of the base of the gas bubble, the gas volume in place as of November 2003.

IP states that using this technique, the volume of gas in place at Hillsboro was calculated to be 14.2 bcf, which represented a shortfall of 8.4 bcf from the gas volumes indicated by accounting records based on the historic injection records. IP note that this was the smallest estimate of the gas volumes in place, and thus the largest estimate of the inventory depletion, developed by the three techniques that IP employed.

d. Metering (Well Chart) Analysis

Illinois Power notes that the third approach it used to determine the Hillsboro inventory depletion was a comparison of injected volumes as measured by the plant turbine meters to injected volumes as measured by the injection meters at the 14 individual wells at the Field, during historic periods when the turbine measurement error was occurring. This comparison was conducted using data from the injection months in the years 1994, 1995, 1998 and 1999. IP stated that to conduct this analysis, data was needed from well chart logs taken from the injection metering at each of the 14 wells. The injection data from the well charts then needed to be integrated on a daily basis to develop a total injection volume for the day that could be compared to the volume injected as measured (incorrectly) on the plant turbine meters. Using the comparisons between the daily volumes recorded on the plant turbine metering and the daily volumes injected at the wells as determined from the integrated well charts, a percentage error (correction factor) for the injection volumes measured at the turbine meters was developed for each injection season. These percentage errors were: 1994, (22.1)%; 1995, (7.0)%; 1998, (12.7)%; and 1999, (8.9)%.

IP asserts that the results of the well chart analysis indicated annual adjustments to the Hillsboro gas inventory of 1.4 bcf to 5.8 bcf, with an average value from the two years for which the well charts were sent to an outside service for integration of 4.9 bcf. IP further states that the upper end of the range of the percentage errors developed through this approach, (22.1)%, was consistent with the inventory shortfall value of 5.8 bcf developed by the reservoir simulation modeling. According to IP, by November 2004, it had reinjected an additional 2.6 bcf of gas into the Hillsboro Field with no gas yet seen at the Field's two key observation wells. IP believes that these results confirmed that the turbine meter correction factors calculated for the two years for which IP performed the chart integration in-house, 1995 (-7.0%) and 1999 (-8.9%), were too low.

IP notes that Staff argued that IP should have used more days of chart data for 1994, 1995, 1998 and 1999, and should have had the well charts for 1995 and 1999 integrated by an outside vendor rather than in-house. IP states that the number of days that could be used was limited by the number of days in each month for which IP had well charts available for all of the injection wells that had operated on that day. For some months there were as few as two days for which chart data for all wells was available, while for other months there were more than five days for which chart data for all wells was available. IP states that overall, the well charts were integrated for virtually all the days in the 1994, 1995, 1998 and 1999 injection seasons for which IP had usable well chart data for all injection wells.

IP argues that it did not integrate well charts for the 1996-1997 injection seasons because the interstate pipelines had changed their definitions of the gas "day," which determined the measurement day used to record injected volumes at the plant turbine meters, from "noon to noon" to "9 A.M. to 9 A.M," but the gas day start time on the individual well meters was not re-set to coincide with the revised gas day until 1998. IP asserts that to overcome this problem would have required that the well chart data be integrated on an hourly rather than a daily basis, which would have required considerably more time to complete, and would have required that IP have two consecutive days of well chart data for all of the wells to match against each day of turbine metering data.

IP argues that using in-house chart integration as opposed to an outside chart integration service. IP acknowledges that it would expect its in-house program to be less accurate (in terms of chart integration, not actual measurements) than a chart integration performed by an outside service, but stated that this only makes the small variances between the injection well measurements and the turbine meter measurements in the 2000 and 2002 analyses more convincing in terms of showing that the well chart method is reliable.

IP asserts that the turbine meters were replaced with the ultrasonic meters because (i) the ultrasonic meters require less maintenance than the turbine meters, thereby providing maintenance cost savings; (ii) replacement of the turbine meters eliminated the need for operating personnel to devote attention to operating the compressors at loadings that did not impact the turbine meter measurements; and (iii) the ultrasonic meters are a newer, more technologically advanced product which provides improved measurement. IP argues that the fact that a newer technology product, which was not available previously, performs better than an older technology product is unremarkable.

IP believes that Staff's emphasis on the fact that the ultrasonic meters provide improved measurement as compared to the turbine meters is irrelevant to the reliability and accuracy of the well chart analysis, which measured the amount of the 1993-1999 turbine metering error based on the difference between the injection volumes recorded by the turbine meters and the injection volumes measured by the metering at the individual injection wells. IP argues that the well chart analyses IP performed for 2000 and 2002, after the cause of the turbine injection metering error was remediated, showed that the integrated well chart metering data from the 14 individual injection wells can be used to accurately depict the amount of gas injected into the Hillsboro Field in a given time period.

IP disagrees with Staff that the turbine measurement error would have fluctuated from month to month because it was a function of the operating rate of the Hillsboro compressors. IP asserts that the three Hillsboro compressors are synchronous motor driven and operate at a constant speed. IP concludes that using an annual correction factor (percentage error) representing an average of the daily data (which is what IP did) was appropriate and that the correction factor was independent of time.

IP asserts that it did not use a single correction factor (percentage metering error) for the entire six-year period to develop an independent estimate of the injection shortfall, but rather used the well chart analysis to develop a range of correction factors (i.e., an average correction factor for each of four years), and also ran the reservoir simulation model iteratively against various correction factors to find the percentage injection metering error (i.e., the actual gas injection history) that best matched the reservoir data as generated by the model. IP explained that a gas injection history that reflected a 22% correction to the recorded injections per the turbine meters, which corresponded to the correction factor calculated by the well chart study for 1994, produced an in-place volume estimate of 16.8 bcf, and thus an inventory shortfall of 5.8 bcf, which best matched the actual reservoir characteristics as generated by the reservoir simulation model.

e. Development of IP's Overall Inventory Depletion Value

IP argues that it employed three independent approaches to develop an overall value of the Hillsboro gas inventory depletion that resulted from the turbine injection meter measurement error over the period 1993-1999. IP states that the chart integration analysis measured gas volume by gas flow; the volumetric analysis measured gas volume based on a neutron log response to gas in the reservoir; and the reservoir simulation modeling measured volume by using sensitivity analysis to find an injection/withdrawal profile that matched the Hillsboro reservoir's pressure responses. IP notes that the well chart integration analysis produced a range of average annual correction factors (percentage error) to the recorded injection data of (7.0)% to (22.1)%. IP further notes that the volumetric analysis produced a value of gas in place of 14.2 bcf, indicating an inventory depletion of 8.4 bcf. IP notes that the reservoir simulation modeling produced a value of gas in place of 16.8 bcf, which matched an average percentage injection measurement error over the six-year period of 22%, indicating an inventory depletion of 5.8 bcf. IP believes that the reservoir simulation technique, being recognized as superior to the other two techniques because it is a dynamic approach rather than a static approach, was given the primary weight. IP also believes that the well chart integration analyses, which produced correction factors much more consistent with the 5.8 bcf shortfall estimate than with the shortfall estimate produced by the volumetric analysis, helped to confirm that the value produced by the reservoir simulation modeling should be adopted.

In responding to Staff's contention that the adjustment to the Hillsboro base gas inventory should not be included in rate base because the amount by which IP determined the inventory had been depleted is an estimate, IP argues that estimates are frequently employed in setting rates. According to IP, one of the most significant components in the ratemaking calculation, the cost of common equity, is an estimate. IP noted that in this case the Staff cost of capital witness frequently referred both to her recommended cost of common equity and to many of the inputs she used in her analysis as "estimates". IP asserts that, more generally, the entire concept of the test year revenue requirement is an estimate that the utility's adjusted, historical revenue requirement (for an historic test year) or its forecasted revenue requirement (for a future test year) will equal its actual revenue requirement during the period the new rates are in effect. IP cites other examples of the use of estimated values in setting rates, including the use of estimated asset service lives and salvage values to establish depreciation rates which are used to determine depreciation expense as well as the accumulated provision for depreciation; and pension expenses which are based on actuarial estimates.

IP argues that the overall inventory depletion value was based on a detailed evaluation of the available comprehensive data base and used state-of-the art, industry-accepted techniques, and that the value of 5.8 bcf, including the 1.8 bcf base gas inventory depletion amount, which has been reinjected, is reasonable and sufficiently reliable to use in establishing the base gas inventory value to be included in rate base in this proceeding. IP further argues that to accept Staff's recommendation to include only the 1993 value in rate base, would assume that no changes to the Hillsboro base gas inventory value have occurred since 1993.

f. IP's Response to Staff's Prudence Argument

IP objects to Staff's introduction for the first time in its Initial Brief of its argument that IP's proposed adjustment to the Hillsboro base gas inventory should be disallowed because IP had not acted prudently. IP states that it believed Staff's concern was that IP's calculation of the amount of the inventory depletion was not accurate enough to use in setting rates. IP argues that nowhere in Staff testimony did Staff contend that IP's base gas inventory amount should be disallowed because it resulted from imprudent management by Illinois Power.

IP argues that while there may be strictly legal issues, a proposed prudence disallowance is not such an issue. IP believes that a determination of a prudence issue requires analysis of management decisions and actions relating to the event in question based on the information available at the time the decisions and actions occurred, and therefore is specifically fact based. IP also believes that it cannot respond to disallowance theories that are not articulated in other parties' testimony.

g. IP's Investigation of the Cause of the Hillsboro Deliverability Decline

IP notes that Staff's prudence argument focused on several specific assertions with respect to one of the withdrawal meters at Hillsboro. IP argues the issues raised by Staff concerning the withdrawal metering had nothing to do with the cause, identification and correction of the injection metering error, which was the actual cause of the Hillsboro inventory depletion. IP asserts that at the time the injection metering error was occurring, its manifestation was a decline in the deliverability performance of the Hillsboro Field, which was the problem IP was facing at the time the decisions and actions in question were being made and taken. IP argues that only in hindsight was it known that the cause of the Hillsboro deliverability decline (and thus of the inventory depletion) was a turbine injection metering error.

IP asserts that it acted aggressively and proactively, and expended considerable resources, in attempting to identify and resolve the causes of the Hillsboro Storage Field deliverability decline. IP further asserts these efforts resulted in the identification and correction of the injection metering measurement error that was the cause of the Hillsboro inventory depletion and thus of the Field's performance decline.

IP first observed that there could be a potential problem with Hillsboro following the 1995-1996 winter withdrawal season (i.e., after the third year of operation of the expanded Field). IP claims that a low amount of gas withdrawals in a single inject-withdraw cycle would not necessarily lead one to suspect a problem, since exogenous factors such as weather and other load constraints could impact the volume of gas cycled in a given year. IP further notes that, at least one of the early years was warmer than normal, meaning that withdrawing less than 7.6 bcf in the winter season would not be unusual. IP believes that observation of reduced or declining deliverability over several years would be necessary for IP to suspect that there could be a physical or operating problem that was reducing deliverability.

IP notes that it initially focused its investigation on whether there was a reservoir problem with the Hillsboro Storage Field, that is, whether either (i) gas injected into the Field was migrating from the underground structure, or (ii) the shape of the underground structure was different than what had been expected. IP notes that the result in either situation would be that gas injected into the Field was moving or being pushed to areas where it could not be reached by the withdrawal wells. IP explains that it then conducted the tests outlined above.

IP notes that it continued to investigate including drilling a new well to the northeast of the Field where the 3-D analysis indicated a sub-structure existed to which gas had migrated from the main reservoir but upon completion of this well, however, in 2000, it was discovered that there was not in fact a separate sub-structure in that area. IP notes that it had an outside consultant perform a crosswell seismic survey involving four wells at Hillsboro. IP further notes that it performed well stimulation treatments, performed additional neutron log analyses, to determine if there was leakage from the reservoir to a shallower formation. IP states that it also conducted flame ionization surveys, which are tests conducted at ground levels to identify any migration of gas at the surface that would not be detected through the neutron logs and that it performed analyses to determine if gas being withdrawn was actually recirculating through the plant equipment and back in to the Field.

IP notes that it conducted analyses of water levels and water production at Hillsboro's observation wells over time and that these analyses indicated that the volume of gas in the reservoir was decreasing. IP further notes that these analyses also showed that the working gas volumes in the reservoir had declined to below the 3.6 bcf working gas volume of the Field prior to the 1993 expansion. IP states that this observation indicated that the source of the deliverability decline was not structural, because if the cause of the problem were structural, the working gas volumes would have stabilized at the pre-expansion levels of 3.6 bcf. IP also had a volumetric analysis performed, using data on the volume of the reservoir and gas saturation data from the reservoir to develop an estimate of gas volumes actually in the reservoir at different points in time.

IP argued that it first attempted to determine if the cause of the Hillsboro deliverability decline was a structural problem with the recently expanded reservoir and if so, what the specific problem was. IP believes that this was a logical and plausible area of investigation to pursue given that Hillsboro had undergone a significant expansion in 1993 but after that expansion was not performing as anticipated. IP notes that it expended considerable internal and external resources on these investigations and analyses. IP further argues that the investigations and analyses into whether there was a potential structural problem led to the ultimate conclusions that (i) the volume of gas in the Hillsboro reservoir had declined significantly since 1993, but (ii) the cause of the volume decline was not a structural problem or other physical problem (e.g., leakage through plant equipment, through the surface or into another underground formation).

IP states that it also separately investigated whether there could be a metering problem. Concurrently with other testing in progress, IP states that it began investigating metering and its consultant identified two metering problems.

IP notes that the first problem was that two new turbine injection meters that had been installed at Hillsboro were over-registering gas injections under certain operating conditions due to the operation of compressors that were located nearby.

IP notes that the second problem was that the orifice opening on one of the plant withdrawal meters was smaller than the value that had been stamped on the equipment at the manufacturer's plant.

IP notes that at the time of the review, the injection metering error at the turbine meters and the withdrawal metering error on the south pipeline secondary withdrawal meter were treated as offsetting. IP asserts that the amount of the measurement error at the withdrawal meter could be calculated with great accuracy, because the amount of the error was simply a function of the difference between the correct and incorrect opening sizes. As a result, IP did not believe it had a sufficient basis to make a gas inventory correction at that time.

IP states that it continued to investigate possible structural causes for the Hillsboro deliverability decline after 2000. IP notes that the volumetric analysis performed in 2002, described above, calculated that the amount of gas in the Field had been depleted by approximately 5.5 bcf since 1993. In addition, a comparison was performed of the gas measured on the plant turbine injection meters for specified time periods to the gas injected at the individual wells as measured by injection metering at the individual wells, for the same time periods. IP states that this comparison showed that the turbine meters had been recording substantially more gas as injected into the Field than had actually been injected, over an extended period of time. According to IP the cause of the Hillsboro deliverability decline was that the gas inventory in the Field had been substantially depleted as a consequence of the injection metering error occurring over time. IP asserts that it was necessary to restate the gas volumes actually in the Field from the volumes shown on IP's accounting records (which were based on the injection metering), and that to return to the design characteristics of the Field, the proper inventory levels must be restored. IP believes that the specific actions required were to (1) determine the gas inventory shortfall that had resulted from the injection metering error; (2) restore the base gas inventory volume to the original (post-expansion) 1993 amount of 14.1 bcf; and (3) reinject gas to restore the 1993 working gas volume of 7.6 bcf. IP notes that reinjections were initiated during 2003 and has been has been completed, that the reinjections planned for 2004 were completed, and reinjection of the full working gas amounts is to be completed during the 2006 injection season.

IP concludes that its actions as summarized above showed that IP acted prudently in investigating the cause of the Hillsboro deliverability decline, isolating and eliminating potential causes, and ultimately identifying the cause, implementing corrective actions to eliminate it and developing and implementing a plan to restore Hillsboro to its 1993 design parameters. IP contends that it was extremely proactive in trying to identify and correct the root causes of the Hillsboro deliverability and inventory problems. IP believes that it investigated multiple possible causes for the deliverability decline, including structural or geological causes (from a real-time perspective, the most likely source of the problem for a storage field that had just undergone a significant expansion), obstructions in the well bores that restricted access to gas in the Field, and metering errors. IP asserts that its corrective actions recommended by outside consultants for identified problems were implemented.

IP argues that the record demonstrated that in investigating, and ultimately identifying and resolving, the cause of the Hillsboro deliverability decline, IP exercised the standard of care that a reasonable person would be expected to exercise under the circumstances encountered by management at the time its decisions were being made and actions being taken, based on the facts available at those times.

h. IP's Response to the Specific Concerns Cited by Staff in Support of its Prudence Argument

IP believes that it has responded to Staff's assertion that "one cause of the measurement errors was an accuracy problem resulting from the orifice opening being smaller then [sic] the value stamped on the orifice plate utilized on IP's withdrawal meters." According to IP, the measurement error that resulted in the inventory depletion occurred solely at the plant turbine injection meters. IP notes that since the error in withdrawal measurement due to the incorrectly sized orifice opening was 2%, while the turbine injection metering error provided to be many times that, there is no basis to conclude that earlier detection of the erroneously labeled orifice opening would have led to earlier discovery of the turbine metering problem.

IP contends that Staff's assertion that "the metering errors related to the orifice meters would have been discovered shortly after their installation if the Company had followed some basic industry standards" was erroneous and misleading on multiple levels. IP argues that it did follow industry standards and that the withdrawal metering error related to only one of the four orifice withdrawal meters.

IP argues that the problem with the orifice withdrawal meter at Hillsboro was not caused by any deterioration due to lack of maintenance, but rather was due to the fact that although the label stamped on the orifice plate in question by the manufacturer stated that the orifice opening was the size that IP had ordered, in fact the orifice opening was somewhat smaller than the labeled (and ordered) size.

IP also argues that since the issue raised by Staff was prudence, which is to be judged under a reasonable person standard and without substitution of one person's judgment for another's judgment, Staff has failed to explain why IP should have been expected to expend the effort and expense (which presumably it would be entitled to recover from its customers) to operate and maintain its storage field metering in accordance with regulations, standards and guidelines that by their terms are not applicable to storage field metering. IP states that such a course would seem imprudent rather than prudent, and inconsistent with the efficient and least-cost operation of IP's facilities. IP also points out that Staff presented no evidence that other Illinois gas utilities are incurring the additional expense necessary to operate and maintain their storage field metering in accordance with regulations, standards and guidelines that by their terms are not applicable.

IP believes that it has responded to Staff's assertion that "IP's load forecasting and dispatch group failed to notice the variance between the volumes of gas received from the pipelines and the amount measured at its Hillsboro storage field," a bcf of gas on average for six years. IP notes that the average Hillsboro injection metering error of about 4,000 mcf per day was less than either (i) the amount of line pack typically in IP's gas system, or (ii) the potential daily variance between transportation customers' nominations and deliveries as allowed under IP's transportation tariff. IP argues that this assertion by Staff is hindsight oriented.

IP also states that in addition to the gas entering its system intended for end users, gas would be entering IP's system on a July day for injection into its storage fields. IP stated that in total, the amount of gas entering its system on a July day could be 220,000 to 280,000 mcf, in contrast to the average daily Hillsboro injection metering error of 4,000 mcf, which would not be noticeable against these total incoming daily volumes. IP believes that Staff's contention that IP's gas dispatchers should have been able to detect the amount of gas being received into IP system but not injected into Hillsboro was unrealistic and unsupported by the record, in light of the totality of the gas volumes on IP's system on a daily basis and the other variables affecting the daily load.

i. IP's Response that IP Should Seek Recovery of the Additional Base Gas Cost through the PGA

IP believes that it responded to Staff's position that IP should seek to recover the $10,367,838 increased cost of Hillsboro base gas inventory through the PGA rather than including the revised base gas inventory cost in rate base. IP argues that this position is at odds with the Commission's PGA rule and is unfounded. IP further argues that while it is currently recovering through the PGA the cost of the original Hillsboro base gas that was withdrawn from storage and supplied to customers, the $10,367,838 amount is the cost of the gas that has been reinjected into the Field to restore the base gas inventory volume. IP argues that Staff's proposal for PGA recovery rather than base rate recovery was completely unfounded and should be rejected.

IP notes that while Staff contended that base gas is typically not expected to be withdrawn until the storage field is retired, that is not what has happened in this case. The original base gas was withdrawn and supplied to customers and new base gas has subsequently been injected to replace it. IP also notes that Staff did not cite any Commission rule or order or other binding provision of law that prohibits the withdrawal of recoverable base gas prior to retirement of a storage field or that requires that the value of a storage field's recoverable base gas be set when the field first goes into service and not be changed thereafter.

3. Commission Conclusion

Based on its review of the record and the arguments of Staff and Illinois Power, the Commission concludes that Illinois Power's base gas inventory value for Hillsboro should be rejected, and that Staff's recommendation to reject IP's base gas inventory value for Hillsboro, and use instead the Hillsboro base gas inventory value that was included in rate base in IP's last gas rate case, Docket 93-0183, be accepted.

The Commission agrees with Staff's position that the cost of the replacement base gas is not recoverable through base rates. Instead, the cost will ultimately be recovered through the Purchased Gas Adjustment Clause when the gas is withdrawn and delivered to PGA customers. What is at issue in this proceeding is not how the cost of the replacement base gas will be recovered, but whether or not IP's shareholders should receive a return on the $10,367,838 increase in their investment in the recoverable base gas that was replaced.

D. Hillsboro Used and Useful Adjustment

1. Staff Position

Staff notes that IP claims the Hillsboro storage field's current operation conditions meet the statutory test of being "necessary" to meet customer demand and "economically beneficial" in meeting customer demand. (IP IB, p. 29). Staff argues that IP reaches this conclusion even though it admits the Hillsboro storage field's annual cycling capability has not been fully restored to its 7.6 Bcf volume value. Staff notes that to support its claim, IP refers to a recent AmerenCIPS and AmerenUE rate case (Docket Nos. 02-0798, 03-0008, & 03-0009 (Cons.)) where Staff produced evidence that indicated that AmerenCIPS' Belle Gent storage field was no longer used and useful and should be removed from rate base. Staff argues, however, that the facts in the two dockets are distinguishable and the comparison is flawed.

In that case, Staff recommended and the Commission ultimately decided to remove the Belle Gent storage field from AmerenCIPS' rate base after Staff's analysis showed the field was no longer needed to provide service to CIPS' customers and the storage field did not provide any economic benefits, and therefore it was no longer used and useful. (Order, Ill C.C. Docket Nos. 02-0798, 03-0008, & 03-0009 (Cons.), p. 28 October 22, 2003) However, according to Staff, IP is ignoring an obvious distinction between the complete removal of a no longer used and useful facility from base rates (the Belle Gent storage field) and making an adjustment based on a facility that is used and useful, but is not operating at its fully Commission certified capacity.

Staff asserts that it presented information in the AmerenCIPS case that indicated the Belle Gent storage field was not needed or economically beneficial, and the Commission determined it was no longer used and useful in any aspect (in other words 0% used and useful) for providing service to customers for the reasons discussed in the Commission's Order. However, according to Staff, the situation facing the Commission in the instant proceeding is not one where Staff is conducting a review of a facility that is no longer used and useful (such as the Belle Gent field), but one where the field is not operating at its Commission certified levels, and thus is not 100% used and useful. Since Staff is not making a recommendation to completely remove the Hillsboro storage field from base rates, Staff did not present any "needs" or "economic benefits" test associated with the Hillsboro storage field. Staff has never argued that the storage field is not necessary to meet customer demand or is not economically beneficial. To the extent that Staff has recommended any percentage of the field be included in rate base Staff has concluded that a portion of the field is necessary and economically beneficial.

Staff argues that IP's own actions support Staff's conclusion that the Hillsboro storage field is not 100% used and useful. Staff notes that IP's concern with replacing the inventory shortfall associated with the field is itself a concession that the field is not currently operating at its Commission certified levels, and thus is not 100% used and useful. In other words, according to Staff, if the Hillsboro storage field were truly 100% used and useful, operating at its Commission certified levels, the Company would not need to immediately replace any inventory shortfall associated with the field. Staff has presented information that indicates the Hillsboro storage field was not and has not for some time been operating in the manner that the Commission certified it. Although the field has again been certified as having a 125,000 peak day capacity, it does not have a working gas inventory of 7.6 Bcf as a result of the manner in which IP has operated the field. To the extent that IP has failed to operate the storage field at the level that the Commission certified it, ratepayers should be relieved of the obligation of funding the storage field at the level the Commission certified it. Staff argues that the field is not 100% used and useful; instead Staff's analysis indicates the Commission should find it 53.44% used and useful and that is the amount of the storage field that should be included in base rates.

a. Three-year period discussion

Staff notes that it used a three-year period for the winter seasons 2001-2002, 2002-2003, and 2003-2004 to review the Hillsboro storage field's peak day and seasonal activity. These winter seasons are the most recent periods where actual operating results are available from the Hillsboro storage field. Actual operating results are essential for the analysis under the circumstances in this docket, where the disallowance is based upon IP's failure to maintain the facility resulting in it no longer being 100% used and useful.

Staff asserts that IP's proposed three-year period relies upon a projection of future Hillsboro storage field operation that is subject to uncertainty. In prior Commission used and useful orders, where the ability of the facility to operate at its expected capacity was never called into question, an analysis based upon projections was reasonable. However, according to Staff, it is clear from the record in the instant proceeding, that the Commission has no assurance that the Company's actions will fully correct its prior deficiencies in operating the Hillsboro storage field. Therefore, Staff's recommendation to make use of the most recent actual data available for the Hillsboro storage field (the winter seasons of 2001-2002, 2002-2003, and 2003-2004) in order to account for the actual operation of the Hillsboro storage field is appropriate.

Staff notes that IP argues that the appropriate three year period to use to determine the used and usefulness of its Hillsboro storage field is the winter seasons 2003-2004, 2004-2005, and 2005-2006. Further, IP indicates that the use of the three-year period that is centered upon the year that rates go into effect is consistent with the Commission's past practices.

In addition to the factual distinctions set forth above, Staff notes the Commission's used and useful calculation has not always followed the pattern advocated by the Company. In particular, Staff indicated the Commission in its February 24, 1993, Revised Order on Remand from Docket Nos. 87-0427/87-0169/88-0219/88-0253/90-0169 Consolidated made use of a three-year average that centered on the test year. Staff argues that the Commission can use its discretion to select the appropriate used and useful period to review based upon the circumstances surrounding the calculation.

Staff argues that unlike past cases involving used and useful analyses that were attempting to place a new fully operational facility into base rates, the Hillsboro storage field was previously found fully used and useful, but based upon its operation, it is no longer 100% used and useful. Staff is not aware of any other instance where the Commission has faced the situation where a utility's inability to maintain a previously certified facility at its certified levels was brought to its attention in a ratemaking proceeding. Therefore, the Commission has the discretion to select the most appropriate time periods to base any used and useful calculation it deems appropriate.

b. Value of Peak Day Capacity

Staff notes that IP also discusses several concerns it has with Staff's valuation of the peak day capacity of the Hillsboro storage field. Staff further notes that IP indicates the use of a single year of peak day capacity is inconsistent with the use of a three-year used and useful calculation. Next, the Company argues the Staff's value is inappropriately based on the capacity costs associated with the NGPL lateral rather than a contract of IP's choosing. Finally, IP claims the use of multiple areas served by Hillsboro should indicate the need for an alterative valuation of the peak day capacity of the Hillsboro storage field.

Notwithstanding the Company's claims, Staff asserts that the peak day valuation is consistent with the valuation of incremental capacity on IP's system in prior proceedings before the Commission that involved the Company. In particular, the peak day valuation amount in this docket was consistent with the value of peak day capacity from Docket No. 01-0701, where Staff determined the annual value associated with 25,000 Mcf/day of capacity on IP's system to equal $900,000, which creates the equivalent value for the 125,000 Mcf/day of Hillsboro peak day capacity of $4,500,000. In fact, Staff proposes and IP did not dispute Staff's valuation that resulted in the $900,000 annual peak day valuation in that docket. Therefore, Staff has demonstrated its peak day valuation method was consistent with past proceedings.

Staff notes that IP made a late claim that Staff's peak day valuation used the wrong contract to make a comparison. Staff's methodology and basis for its peak day valuation was set forth in direct testimony, IP did not raise its concern about the use of the supposedly wrong contractual value until its surrebuttal testimony, when Staff no longer had an opportunity to conduct discovery about or respond in testimony to this new information. However, as indicated above, Staff believes that its valuation of the capacity is consistent with prior cases. According to Staff, IP's attempt to value the peak day capacity of the Hillsboro storage field centers on the use of capacity rates from Natural Gas Pipeline Company of American ("NGPL") and Panhandle Eastern Pipe Line Company ("PEPL"). According to Staff, IP wishes to make use of a contract whose cost is more than twice the cost of a supposedly comparable contract. Further, Staff notes that the PEPL capacity is actually the most expensive transportation supply option on IP's total system. Staff argues that IP's statements ignore the fact that a prudent company would replace missing capacity at the lowest possible rate.

Further, according to Staff, IP itself claims that PEPL capacity is not available; however it is exactly this capacity that IP wishes to place reliance upon to value the peak day capacity of its storage field. Staff notes that IP claims that if it was to rely on this capacity, it would actually pay more for it. Notwithstanding the fact the Company's claim is counter to normal economic theory, Staff fails to be convinced that any utility would purchase the most expensive supply option when other less expensive sources are available.

Staff further notes that the Company claims that since the Hillsboro storage field serves areas principally served by NGPL and PEPL, capacity for both of these pipelines must be used to value the peak day capacity of the Hillsboro storage field. However, Staff noted that the original Hillsboro project from Docket No. 93-0183 also included a 62-mile pipeline to connect its Decatur and Metro-East territories and that this pipeline allowed IP to access additional suppliers and to increase the competition between interstate pipelines and that the Hillsboro storage field itself had no, or very little, impact on this process. Since the territories are interconnected via this 62-mile pipeline and the purpose of the pipeline was to increase the competition between the lines, Staff would expect any loss of capacity from the storage field could be made up from the interconnection associated with this line, therefore, Staff reliance on NPGL capacity contract costs is appropriate.

c. Overall Storage Concerns

i. Docket 01-0701

Staff states that both Dynegy and IP discuss the Commission's Order from Docket No. 01-0701, where Staff had raised overall storage concern arguments that are similar to those raised in the instant proceeding. Staff asserts that both entities attempt to provide the impression that the Commission's rejection of Staff's prudence argument regarding IP's decision to reduce the peak day capacity of the Shanghai storage field from Docket No. 01-0701 was tantamount to a full and complete rejection of the Staff's overall storage concerns in that proceeding. However, according to Staff, a review of the Order shows that it is not the case. Specifically, the Commission concluded in that Order the following regarding the

> Staff's general concerns about IP's gas storage field operations raise interesting issues, but Staff itself states it does not recommend an adjustment related to these concerns. While appreciative of Staff's efforts in compiling these observations about IP's storage field operations, the Commission is unsure how Staff would have the Commission respond. If Staff believes that IP's operations warrant investigation, then the Commission suggests that Staff prepare a report recommending a management audit of IP's gas storage operations, pursuant to Section 8-102 of the Act. (Docket No. 01-0701 Order, p. 24 (February 19, 2004))

Further, the Order also indicated that:

> On a final note, the Commission also cautions IP to not delay investments or upgrades at its storage facilities because it would not earn a return on them until they are considered in a rate case. Staff suggests that IP may be doing just that because it knows it can recover any increased gas costs (stemming from the delayed investment) through the PGA clause as long as it can convince the Commission that such costs are prudent. The Commission does not find in this proceeding that IP is in

> fact doing that, but in light of the general discussion of IP's storage operations the Commission reminds IP of its obligations to properly maintain and invest in its storage fields. (Id., p. 24)

Staff's view of the Commission Order from Docket No. 01-0701 and the above quotes indicates that Staff's concerns were not rejected outright.[10] Staff further argues that IP has not properly maintained its storage fields.

Further, Staff notes that this information corroborated its original analysis and conclusion from Docket No. 01-0701 regarding IP's capital expenditures. Namely, that IP was unwilling to spend capital on its storage activities, which, in turn, has contributed negatively to IP's ability to maintain its storage operations. Further, this above information also suggests that the Company was somewhat less than forthcoming regarding its actions in Docket No. 01-0701. Therefore, Dynegy and IP's attempts to dissuade the Commission from considering the overall storage concerns that condemn IP's actions regarding its storage operations should be rejected.

Staff recommends that the Commission recognize that Staff's overall storage concerns indicate the Company has failed to maintain is storage operations in a manner consistent with the Commission's requirements. In particular, the Company's actions have violated Section 1-102 of the PUA that states, in part that a utility has an obligation to its customer to provide "…adequate, efficient, reliable, environmentally safe and least-cost public utility services which accurately reflect the long-term cost of such services and which are equitable to all citizens."

ii. Reference to Old PGA Case, Docket 02-0721

Staff notes that IP also provided a reference to Docket No. 02-0721 and indicated correctly that Staff did not take issue in that case with the manner the Company operated its storage fields. However, Staff would note that in Docket No. 03-0699, the Company's on-going 2003 PGA reconciliation, Staff recommends that the Commission find the Company imprudent for the manner it operated the Hillsboro storage field during 2003. Further, Staff would note that the manner the Company operated its Hillsboro storage field was also at issue in Docket No. 04-0294, the Section 7-204 proceeding where Ameren sought Commission approval of its acquisition of IP.

iii. Dynegy Indemnification

Staff asserts that Dynegy's positions and arguments in this docket must be viewed in the proper context. Staff notes that according to the terms of the Stock Purchase Agreement that Dynegy submitted for approval in Docket 04-0294, it has agreed to indemnify Ameren in connection with certain potential disallowances in IP's

[10] Staff has at this point cited to a confidential document produced by Ameren in Docket 04-0294 concerning IP's expenditure on projects. IP presented testimony to rebut this presumption and at best the Commission is faced with conflicting positions.

rates. Staff points out that Article IX INDEMNIFICATION, Section 9.1 (g), page 79, of the February 2, 2004 Stock Purchase Agreement among Ameren Corporation, Illinova Generation, Illinova Generating Company and Dynegy Inc. attached to the Application filed in Docket No. 04-0294 states, in part, the following:

> any net refund of amounts under IPC's purchased gas adjustment ("PGA") rider ordered by the ICC, whether effected by adjustment of any PGA factor or otherwise, in any PGA reconciliation proceeding relating to any portion of the period from January 1, 2001 to December 31, 2004, to the extent that payments or PGA adjustments required to be made by IPC pursuant to such order exceed the reserve established for potential liability in such proceeding as reflected in the calculation of the Final Adjusted Working Capital; or any disallowance by the ICC of IPC's gas costs or investment relating to events prior to the Closing at the Hillsboro gas storage field whether such disallowance shall be provided for in any PGA case ("working gas") or in a gas rate case ("cushion gas"), but only to the extent that such disallowance is not due to any imprudence by IPC after the Closing; provided, however, that the Seller Indemnitors' liability under this Section 9.1(g) with respect to any such refund or disallowance shall be equal to 50% of such refund or disallowance.

According to Staff, this clause provides assurance to Ameren that in the event that the Commission determines that IP's actions or lack thereof regarding its Hillsboro storage field were not prudent through the end of calendar year 2004 (assuming IP took or failed to take those actions prior to the closing of the acquisition of IP by Ameren), that IP would be responsible for only half of the prudence disallowance with the other half being paid by Dynegy. Although Staff is not suggesting any improper conduct by Dynegy in raising the arguments it makes in its initial brief, the fact remains that Dynegy's interest in this case is in avoiding payments under its indemnification obligation. Staff argues that this fact must be kept in mind in considering Dynegy's arguments.

2. Illinois Power Position[11]

IP argues that although the underlying premise of Staff's proposed used and useful disallowance is that the Field is not performing at the design levels represented to the Commission when the investment in the expanded Field was placed into rate base, Staff has failed to use the relative weighting of the Field's peak day capacity savings and seasonal gas cost savings presented in that rate case (Docket 93-0183) in its calculations. According to IP, Staff used a weighting based on peak day capacity and seasonal gas cost savings that it calculated using data for the period 1999-2000 through 2003-2004. IP states that use of the same relative weighting of the Field's peak day capacity savings and seasonal gas cost savings that was presented in Docket

[11] Dynegy has filed briefs in this docket that echo IP's position so a separate Dynegy section was not deemed necessary.

93-0183, when the expanded Field was placed in rate base, shows Hillsboro to be 96.8% used and useful.

It is IP's position that in its current operating condition, the Hillsboro Storage Field satisfies the criteria contained in Section 9-212. IP states that the peak deliverability rating of Hillsboro was reduced from its "design" value of 125,000 mcf/day to 100,000 mcf per day prior to the 1999-2000 winter season, but that the rating was restored to 125,000 mcf/day prior to the 2003-2004 winter season, and this peak day deliverability rating was confirmed through a test on January 30, 2004. IP notes that Staff agreed that IP is presently operating its storage fields at their rated peak day capacities. IP states that for the 2004-2005 winter season, IP injected 4.6 bcf of working gas into the Hillsboro Field, and is prepared to withdraw 4.1 bcf of working gas during this winter season to supply to customers. IP states that at these capacities, Hillsboro is "necessary" to meet customer demand and "economically beneficial" in meeting customer demand.

With respect to the "economically beneficial" criterion, IP presented a calculation of the annual savings in interstate pipeline firm transportation ("FT") charges that is produced by Hillsboro's 125,000 mcf/day of peak deliverability (assuming that pipeline firm transportation capacity into the region served by Hillsboro could in fact be obtained to replace the entire deliverability of the Field). IP also provided a calculation of the seasonal gas cost savings produced by cycling 4.1 bcf of gas, which is the amount being cycled in the 2004-2005 winter. IP also provided a calculation of the annual revenue requirement for the Hillsboro Field, including O&M costs, depreciation and return on the full investment at the rate of return last proposed by the Staff rate of return witness in this case, 8.25%. IP's calculations showed that at its current operating levels, the gas cost savings provided by Hillsboro substantially exceed the revenue requirement associated with including Hillsboro in rate base as 100% used and useful. Based on this comparison, IP argues that Hillsboro is "economically beneficial" in meeting IP gas customers' service demands.

IP points out that Staff did not present an "economic benefits" test in this case of the form presented by IP witness Shipp, and that Staff did not even acknowledge the appropriateness of this test after it was presented by IP. IP notes, however, that this was the form of test that Staff submitted to the Commission in a recent AmerenCIPS/AmerenUE rate case in which Staff argued successfully that the Belle Gent storage field was no longer used and useful under Sections 9-211 and 9-212 of the PUA and should be retired.

It is also IP's position that Hillsboro is "necessary to meet customer demand." IP stated that at its current operating level, which was in effect for the 2003-2004 winter season as well as the 2004-2005 winter season and was confirmed by a capacity test on January 30, 2004, Hillsboro provides 125,000 mcf of peak day deliverability. The capacity of the Hillsboro Field serves the Metro East area and the Decatur area. (Rev. IP Ex. 3.19, p. 11) IP pointed out that in terms of interstate pipelines, the Metro East area is served by Natural Gas Pipeline Company of America ("NGPL") and Mississippi

River Transmission Corporation ("MRTC"), while the Decatur area is primarily served by Panhandle Eastern Pipe Line Company ("PEPL"), although it is also served by NGPL. IP stated that in the current market, PEPL is fully subscribed and at least one of the mainline legs of NGPL into Illinois is fully subscribed. Further, most of IP's transmission capacity into Decatur from NGPL is utilized by retail transportation customers. IP concluded that there may not be sufficient available pipeline FT capacity on NGPL and PEPL to replace the entire 125,000 mcf/day of Hillsboro capacity. (Rev. IP Ex. 13.1, p. 13) Therefore, if the Hillsboro Field did not exist, it likely would not be possible to replace its peak deliverability capacity with pipeline FT. IP concluded that Hillsboro meets the "necessary to meet customer demand" criterion for being fully used and useful because it provides necessary peak day capability to the IP gas system and its customers that may not be obtainable from other sources (i.e., the interstate pipelines).

a. Three-Year Period

IP states that the Commission should question whether using three-year averages to determine the used and useful status of Hillsboro is appropriate for purposes of this case and whether instead only the most current information, representing the operating condition of Hillsboro and gas market conditions and prices immediately prior to the rates set in this case going into effect, should be used for any used and useful calculations. IP argues that assuming the Commission decided a three-year analysis is appropriate, the three-year period that should be used consistent with prior Commission orders is 2003-2004, 2004-2005 and 2005-2006.

IP disagrees with Staff's selection of its three-year period based on the orders cited. IP asserts that in Docket 84-0055, for which the test year was 1986 and the order was issued in March 1989, the Commission used the three years 1988, 1989 and 1990 in its used and useful calculation. IP notes that in Docket 89-0276, for which the test year was 1990 and the order was issued in June 1990, the Commission used the three years 1989, 1990 and 1991. In Docket 91-0147, in which the test year was 1992 and the order was issued in February 1992, the Commission looked at several three-year periods in making its used and useful determination: 1991-1993, 1992-1994 and 1993-1995. IP argues that a consistent thread among these three cases is that the three-year period the Commission used consisted of the year prior to the year of the order, the year in which the order was issued (i.e., the year in which the new rates went into effect) and the year following the order. IP argues that applying the same approach to the circumstances of this case, the three years that should be used are 2003-2004, 2004-2005 (2005 being the year the new rates go into effect) and 2005-2006. IP points out that in none of the three cases relied on by Staff did the Commission use a three-year period that completely preceded the order date.

IP argues that the resolution of this issue in Docket 94-0065 would require the three-year period of 2003-2004, 2004-2005, and 2005-2006.

IP asserts that the decision as to which three-year period to use in this case is not merely an academic exercise. IP believes that in two of the three years Staff used, Hillsboro was rated at 100,000 mcf/day peak deliverability, whereas in each of the three years 2003-2004, 2004-2005 and 2005-2006, the rating is 125,000 mcf/day peak deliverability.

b. Value of Peak Day Capacity

IP argues that Staff's calculation of the peak day capacity cost savings benefit produced by Hillsboro was flawed in several respects. IP notes that Staff used a price taken from just one of IP's current pipeline FT contracts for the cost of replacement pipeline FT capacity, the rate in IP's contract associated with the NGPL Metro East Lateral.

IP argues that Staff's use of a single FT rate from a single year (2003) was inconsistent with the approach of using a three-year average for Staff's used and useful calculations, as well as with its use of five years of historical data to calculate the seasonal gas cost savings.

IP argues that the FT price Staff elected to use was for transportation on an NGPL lateral that runs only from Centralia, Illinois to the Metro East area, entirely within the IP service area. IP states that it is not a long-haul contract and does not include the cost of firm pipeline transportation from the gas producing fields to the IP service area. IP stated that this contract falls far short of representing the full cost to replace Hillsboro's peak day capacity with pipeline FT. IP asserts that in contrast, the pipeline FT costs that IP used in re-doing the calculations were representative of the full costs of pipeline FT from the gas producing fields in the Mid-continent area (Texas-Oklahoma-Kansas) and the Gulf Coast area (Texas-Louisiana) to IP's service area. As a result, according to IP, the pipeline FT costs that it used, and the resultant peak day capacity cost savings benefit calculated, were considerably higher than those calculated by Staff.

IP argues that Staff erroneously asserts that if IP were to replace the entire capacity of the Hillsboro Field with pipeline FT, IP should be able to obtain greater discounts from the prices it currently pays for pipeline FT capacity. IP states that PEPL is fully subscribed and at least one of the NGPL mainline legs into Illinois is fully subscribed. As a result, IP argues, these pipelines basically have no reason to give significant discounts in order to sell large blocks of incremental FT capacity.

c. Seasonal Gas Cost Savings

IP contends that Staff's use of five years of historic data was flawed. IP argues that to accept Staff's calculation of the seasonal gas cost savings to be expected from the Hillsboro Field, the Commission would have to assume that IP bought gas for injection during the 2004 injection season at the same prices it purchased gas for injection in 1999, 2000 and 2001, and that it will be able to buy spot commodity gas during the 2004-2005 winter at the same prices for which gas was purchased in the 1999-2000, 2000-2001 and 2001-2002 winter seasons. IP further argues that due to the relatively recent installation of almost 200,000 mW of gas-fired electric generation in the U.S. which has increased the demand for gas during the summer, there are now periods in which gas prices in the winter heating season are not significantly different than prices in the summer.

IP argues that the appropriate comparison to calculate Hillsboro's seasonal gas cost savings benefit would be to compare the cost of gas when it is injected into the Field to the spot price of gas at the time of withdrawal, utilizing futures prices, not historical prices. In re-doing Staff's calculations, IP used a comparison between New York Mercantile Exchange ("NYMEX") prices for (i) gas deliveries in the April 2005 to October 2005 period and (ii) gas deliveries in the November 2005 to March 2006 period. These are prices quoted on the NYMEX for contracts for delivery of gas in those months. IP asserts that consistent with the proposition that the determination of whether the Hillsboro Field is used and useful for the purpose of setting rates that will go into effect in May 2005 and be in force thereafter should be based on the current and reasonably foreseeable operating status of the Field, NYMEX gas futures prices, rather than five-year old price data, should be used to calculate the seasonal gas cost savings benefit that Hillsboro produces.

IP further argues that in calculating the Hillsboro used and useful percentage, Staff took the amount of gas cycled in each of the three years 2001-2002 through 2003-2004 as a percent of 7.6 bcf, the maximum "design" working gas inventory of the Field. This approach assumes that the entire 7.6 bcf working gas inventory should be withdrawn from the Field each winter season to be supplied to customers. IP asserts that this is an unrealistic assumption, because the entire amount of working gas inventory in a storage field will not necessarily be withdrawn in every year. IP argues that it is not realistic to assume that the entire working gas inventory of a particular storage field would be cycled every year.

d. IP's Recalculation of Staff's Used and Useful Calculation

IP recalculated the Hillsboro used and useful percentage using Staff's methodology but (i) using the three years 2003-2004, 2004-2005 and 2005-2006 rather than the earlier three year period used by Staff; (ii) using the full 125,000 mcf/day peak deliverability rating of Hillsboro for each of the three years, (iii) using as the replacement pipeline FT price the average of the prices paid to NGPL and PEPL in IP's most recently negotiated contracts with these pipelines, and (iv) using NYMEX futures contracts prices for the summer injection and winter withdrawal seasons to develop the seasonal price differential, rather than historical prices that were as much as five years old, as employed by Staff. Using these parameters and inputs, IP calculated an 84.33% used and useful percentage for Hillsboro, in contrast to the 54.33% used and useful percentage of Staff.

e. Used and Useful Calculation Using Weightings of Peak Capacity Savings and Seasonal Gas Cost Savings

IP argues that the entire premise for Staff's proposed used and useful adjustment was that the expanded Hillsboro Field has not provided the peak day deliverability and annual working gas volume that was planned when the investment in the expanded Field was placed in rate base in Docket 93-0183. IP points out that in Docket 93-0183, the rate case in which the investment in the expanded Hillsboro Field was placed in rate base, IP presented a calculation of the value of the peak day savings benefits and seasonal gas cost savings benefits expected from the expanded Field. IP states that consistent with Staff's underlying rationale, the calculation of whether and to what extent Hillsboro is used and useful should have been based on the relative weightings of the peak day savings and seasonal gas cost savings benefits presented to the Commission in Docket 93-0183. In Docket 93-0183 IP represented to the Commission that the expanded Hillsboro Field was projected to produce annual savings of $13,599,000 in reduced pipeline charges and $997,500 due to increased seasonal gas purchases. Thus, 93% of the savings from the Hillsboro expansion were from the Field's increased peak day deliverability while 7% of the savings were from increased seasonal gas purchases. IP stated that if these percentages are inserted into Staff's used and useful calculation with no other changes to its calculations, the result of Staff's calculations would be that Hillsboro is 85% used and useful, not 53% as calculated by Staff. Further, if Staff calculations were based on the three-year period 2003-2004 through 2005-2006, meaning that 125,000 mcf/day is used as the Field's actual peak day capacity for all three years and the amount of gas cycled on average for the three years is 53.58% of the 7.6 bcf maximum, then Staff's calculations would show Hillsboro to be 96.8% used and useful.

f. IP's Response to Staff's Overall Storage Concerns

IP argues that the "overall storage concerns" Staff identified do not provide for Staff's proposed used and useful adjustment to Hillsboro. IP further argues that the deliverability decline at the Hillsboro Storage Field was caused by a measurement error in the plant injection meters which resulted in IP injecting less gas into the Field than it believed it was injecting based on the plant meter readings. IP also contends that it was extremely proactive, worked diligently over a period of years, pursued several avenues of investigation and expended considerable resources, in attempting to find the cause of the deliverability declines.

g. Reduction in Peak Day Capacity

IP's response to Staff's "overall storage concern" that in recent years, is that IP has reduced the peak deliverability ratings on two of its storage fields, Hillsboro and Shanghai. IP points out that Staff acknowledged that IP is operating its storage fields at their rated peak day capacities.

h. Manpower

Part of Staff's "overall storage concerns" was that over the period from 1991 to 2000, IP reduced the number of supervisors at its storage fields from four to one. IP asserts that Staff acknowledged that the number of storage field operators has remained stable since 1991.

i. Capital Expenditures

IP disputes Staff's "overall storage concern" that IP's budgeted capital expenditures for its storage fields were lower in recent years (2002-2004) than in earlier years (2000-2001), and that IP was unwilling to make capital expenditures since the costs are not recoverable through the PGA. IP argues that Staff admitted that it was not in possession of detailed information about IP's capital budgeting procedures for its storage field operations. IP disputes Staff's assertions and believes that the record shows that IP in fact has been proactive in identifying and correcting problems at all of its storage fields, and has initiated numerous projects to avoid potential problems while trying to ensure maximum deliverability ratings.

IP asserts that it plans for capital improvements for its storage fields on a rolling five-year basis and has implemented all the projects and enhancements at its storage fields over the period 1995-2003, and provided a list of all the studies that IP performed on its storage fields during the period 1998-2003.

j. December 2000 Hillsboro Incident

Staff asserts that IP failed to conduct an adequate root cause analysis in connection with a December 2000 incident at the Hillsboro Field in which a produced water tank became over pressurized and was launched from its foundation, resulting in damage to other structures and equipment and an outage at the Field. IP asserts that this incident has been a topic in several previous dockets including Docket 00-0714 and Docket 01-0701. IP further asserts that it promptly hired an outside firm to conduct an investigation of the incident and submit a report; that the Commission's Office of Pipeline Safety ("OPS") conducted an investigation and issued a report; the OPS report did not make any findings of violations; nor reach a conclusion on the cause of the incident.

IP asserts that it implemented a number of corrective actions pertaining to the equipment involved in the incident and its operation to attempt to prevent a repeat of the incident. According to IP, Staff did not criticize as insufficient, incomplete or inappropriate any of the corrective actions that IP implemented in response to the December 2000 incident, which were itemized in the record.

k. Hillsboro Storage Field Metering

IP's response to Staff's "overall storage concern" that IP did not pull and inspect the orifice plates on the Hillsboro well withdrawal meters from their installation in 1993 to the time of the Peterson metering review in 1999, is that Code Part 500 applies only to utility meters used to measure customer loads and therefore is inapplicable to the metering at the Hillsboro Field. IP asserts that although the orifice plates were not pulled for inspection from 1993 to 1999, when they were pulled they were found not to have degraded after six years of service and to still be service worthy. Further, IP did have an inspection procedure for these meters, consisting of calibrating the differential transmitters of each orifice meter fitting, calibrating the pressure transmitters for each pipeline, and checking the calibration of the resistant temperature detectors for proper temperature input, as well as checking the signal tubing between the orifice fitting and the differential transmitter on each meter for fluids.

IP argues that in any event the problem with the orifice withdrawal meter at the Hillsboro Field was not caused by deterioration due to a lack of maintenance but rather was due to the fact that the label placed on the orifice plate by its manufacturer stated that the orifice opening was the size that Illinois Power had ordered, when in fact the orifice opening was somewhat smaller than the labeled (and ordered) size. IP further argues that neither the incorrect size of the orifice meter plate opening nor the level of maintenance on the orifice metering was the cause of the deliverability decline experienced at the Hillsboro Field.

l. Gas Dispatch Tracking

Staff's final "overall storage concern" was that IP's gas load forecasting and dispatch group failed to notice an extra bcf of gas entering its system each year and that this was an example of IP failing to adequately oversee its operations. IP points out that, particularly during the months of April, May, October and November, when the purchased volume on any day is approximately 300,000-400,000 mcf, with approximately 120,000 mcf being injected into storage, 4,000 mcf would not stand out as a significant error. IP asserts that volumes of customer-owned gas also enter the system and that on a real-time basis the dispatchers cannot distinguish between deliveries for transport customers and other deliveries into the system.

IP also notes out that on any given day the line pack in IP's system could range from zero to 10,000 mcf. According to IP, the additional amounts of gas that were entering the distribution system on a daily basis due to the Hillsboro injection metering error were less than the amount of gas IP typically has in its system as line pack. IP further asserts that although its gas dispatchers know what actual pipeline deliveries are on any day, the dispatchers do not know the actual customer consumption on any given day to enable them to compare the two values to determine if the load is equal to deliveries.

m. Efficiency of Storage Field Operations

Illinois Power presented several analyses depicting the overall efficiency of its operation of the Hillsboro Storage Field relative to other storage fields, in response to generalized assertions by Staff that IP was not fulfilling its obligation to provide adequate, efficient, reliable, environmentally safe and least-cost public utility services. IP believes that these analyses show that Hillsboro has been operated efficiently relative to other storage fields, Staff's criticisms notwithstanding.

3. Commission Conclusion

Based on its review of the record and of the arguments of Illinois Power and Staff, the Commission concludes that the Hillsboro Storage Field should be found to be 53.44% fully used and useful for purposes of this case, and that Staff's proposed used and useful adjustment should be adopted. The Commission finds that the economic benefits Staff assigned to the Hillsboro storage field's peak day and seasonal capacity are reasonable and appropriate for use in determining the used and usefulness of the Field. Whereas the Commission does note the Company indicated the Field is fully used and useful because it is needed and provides economic benefits, the Company's review fails to account for the prior Commission Orders regarding the certified operating levels of the field and ignores the loss of benefits to ratepayers from operating the Field below its certified levels. As such, Staff's used and useful analysis properly accounts for both the economic loss associated with the Field and the reduction in operating levels.

The Commission agrees with Staff that it has the discretion to select the most appropriate period to form the basis of the used and useful analysis. Given the unique nature (i.e. a previously certified facility no longer operating at the Commission certified levels) of the events surrounding the Hillsboro storage field's loss of capacity, the Commission is persuaded by Staff's arguments that only known information should be used to review the used and usefulness of the Hillsboro storage field. Therefore, the winter seasons of 2001-2002, 2002-2003, and 2003-2004 are the appropriate periods to review for the used and usefulness of the Hillsboro storage field.

E. Overall Conclusion on Rate Base

Based on the gas utility rate base as originally proposed by IP, the uncontested adjustments to rate base as summarized in Section III.A above, and the Commission's conclusions with respect to the Hillsboro Storage Field base gas inventory and the Hillsboro Storage Field used and useful status in Sections III.C and III.D, above, the gas utility rate base for AmerenIP approved for purposes of this proceeding is $468,845,000. The rate base may be summarized as follows:

Approved Rate Base
($ x 1000)

Gross Utility Plant in Service	$ 843,776
Less Accum. Deprec. and Amort.	(415,113)
Net Plant	428,663
Additions to Rate Base	
Cash Working Capital Allowance	(1,073)
Gas Stored Underground -Noncurrent	11,840
Depr. Res.-Contrib. Electric Distribution	1,164
Materials & Supplies and Working Gas Inv.	41,430
	-
Deductions From Rate Base	-
Accum. Deferred Income Taxes	-
Customer Advances for Construction	(6,703)
Customer Deposits	(6,476)
Pre-1971 ITC's	-
Rate Base	$ 468,845

The development of the overall gas utility rate base adopted for purposes of this proceeding is shown in the Appendix to this Order.

IV. GAS DEPRECIATION RATES

As part of its filing in this case, Illinois Power requested approval of revised depreciation rates for its gas utility. IP last performed a gas depreciation study in 1992; the results of that study were approved by the Commission in Docket 92-0465 and were incorporated into the setting of IP's gas rates in its last gas rate proceeding, Docket 93-0183.

IP's proposed revised depreciation rates are based on a study prepared for IP by Foster Associates, Inc. (IP Ex. 11.3) Dr. Ronald E. White, Executive Vice President and Senior Associate of Foster Associates, sponsored the depreciation study and submitted prepared testimony describing it. (IP Ex. 11.1) He testified that Foster Associates is recommending a separation of the accrual rate for net salvage from the accrual rate for the investment portion of a plant account. Under this approach, depreciation charges for the investment portion of a plant account will be accumulated in primary account investment reserves, while net salvage accruals will be accumulated in function net salvage reserves. He stated that the benefits derived from a separate accrual rate for net salvage include reduced field reporting, simplified accounting and improved monitoring and control of reserve imbalances. However, Foster Associates is not recommending separation of the accrual rates for net salvage and the investment portion of the plant accounts for general plant accounts, because gross salvage and cost of removal for plant items classified as general plant are generally easier to identify than net salvage associated with transmission and distribution accounts.

Dr. White also testified that an analysis comparing the computed and recorded depreciation reserves for IP at December 31, 2003, showed a difference of $(27,192,728) between the recorded depreciation reserve and the computed reserve. He testified that a proportionate amount of this measured reserve imbalance would be amortized over the composite weighted-average remaining life of each depreciation rate category.

Finally, Dr. White testified that Foster Associates is recommending a rebalancing of depreciation reserves for IP. This will entail (i) maintaining recorded reserves by primary account, which IP has not done in the past, and (ii) separating the recorded reserve into an investment portion and a net salvage portion, such that net salvage can be recorded at the function level and depreciation expense exclusive of net salvage can be accrued by primary account. He explained that a redistribution of the recorded reserve is therefore necessary to develop an initial investment reserve balance for each primary account and a net salvage reserve balance for each function consistent with the estimates of retirement dispersion and net salvage rates developed in Foster Associates' study. Dr. White explained how the redistribution of the recorded reserve was calculated.

IP's current Commission-approved depreciation rates were established at the function level (with the exception of general plant) and are as follows:

Underground Storage		1.76%
Transmission		2.29%
Distribution		3.60%
General Plant		
Structures and Improvements	2.04%	
Transportation Equipment	4.81%	
Tools, Shops and Garage Equipment	4.20%	
Laboratory Equipment	4.20%	
Power Operated Equipment	3.89%	
Miscellaneous Equipment	4.20%	
Total General Plant		4.41%
Total Gas Utility		3.25%

The following table shows the proposed depreciation rates, by account (IP Ex. 11.3, p. 16):

Account Description	**Proposed Rate**
Underground Storage	
351.20 Compressor Station Structures	1.64%
351.30 Meas. and Reg. Stations	1.72%

351.40 Other Structures	1.76%
352.00 Wells	1.71%
352.20 Reservoirs	1.59%
352.30 Nonrecoverable Natural Gas	1.26%
353.00 Lines	1.96%
354.00 Compressor Station Equipment	2.09%
355.00 Meas. and Reg. Equipment	2.41%
356.00 Purification Equipment	1.74%
357.00 Other Equipment	2.42%
Total Underground Storage	1.81%
Transmission	
366.00 Structures and Improvements	1.32%
366.10 Compressor Station Structures	2.04%
366.20 Meas. and Reg. Station Structures	2.23%
366.30 Other Structures	2.40%
367.00 Mains	1.22%
368.00 Compressor Station Equipment	1.96%
369.00 Meas. and Reg. Station Equipment	2.12%
Total Transmission Plant	**1.39%**
Distribution	
375.00 Structures and Improvements	1.51%
376.00 Mains	1.97%
378.00 Meas. and Reg. Equipment – General	1.99%
379.00 Meas. and Reg. Equipment – City Gate	2.96%
380.00 Services	2.17%
381.00 Meters	2.18%
382.00 Meter Installations	2.82%
383.00 House Regulators	2.82%
385.00 Industrial Meas. and Reg. Station Equip.	2.80%
Total Distribution Plant	**2.17%**
General	
390.00 Structures and Improvements	2.32%
392.00 Transportation Equipment	0.97%
394.00 Tools, Shop and Garage Equipment	2.12%
395.00 Laboratory Equipment	0.91%
396.00 Power Operated Equipment	2.53%
398.00 Miscellaneous Equipment	3.05%
Total General Plant	**1.66%**
TOTAL INVESTMENT	**2.00%**
Net Salvage	
108.42 Underground Storage	0.19%

108.43 Transmission	0.26%
108.44 Distribution	1.04%
TOTAL NET SALVAGE	**0.83%**
TOTAL UTILITY	**2.81%**

A comparison of the current depreciation rates to the proposed depreciation rates shows that the proposed accrual rates are lower than the present rates in 27 of the 36 primary accounts included in the Foster Associates study. Dr. White calculated that based on December 31, 2003 plant balances, adoption of the proposed depreciation rates would reduce annualized depreciation expense by $3,200,674. (IP Ex. 11.1, p. 16)

Staff witness Burma Jones reviewed IP's depreciation study. She testified that the current case is the proper venue for IP to propose a change to its depreciation rates given that it has been approximately eleven years since the last change in IP's depreciation rates. She stated that the current depreciation study was warranted and that the results appear reasonable; therefore, she stated that she had no objection to the proposed depreciation rates. No other party raised any issues concerning, or stated any objection to, the proposed depreciation rates.

Based on its review of the record, including the depreciation study submitted by IP, the Commission concludes that IP's proposed depreciation rates are reasonable and should be approved. The Commission concurs with Staff as well as IP that a review and revision to IP's depreciation rates is timely in connection with this proceeding. The Commission concludes that the separation of the accrual rates into an investment portion and a net salvage portion, the redistribution of the recorded reserve and the amortization of the reserve imbalance as estimated in the Foster Associates study, and the incorporation of these steps into the development of the proposed depreciation rates, as described in IP Exhibit 11.3, are reasonable and should be approved, pursuant to Section 5-104(a) of the Act (220 ILCS 5/5-104(a)).

V. OPERATING REVENUES AND EXPENSES

Illinois Power's proposed operating income statement, as presented in its direct case filing, was based on test year 2003 actual expenses as adjusted by a number of proposed pro forma adjustments. Some of these adjustments were objected to by other parties while others of these adjustments were not objected to by other parties. Additional adjustments to operating revenues and expenses were proposed by Staff and/or AG/CUB and were accepted by IP. Finally, as discussed in Section I of this Order, above, IP and Staff stipulated to the resolution of certain proposed adjustments to operating expenses as set forth in the Stipulation, and no other party objected to these Stipulated Resolutions. As a result, as of the close of the record, there were no remaining contested adjustments to operating revenues and expenses. The uncontested or agreed adjustments to operating revenues and expenses that are being adopted for purposes of this Order are discussed in Section V.A below.

A. Uncontested Adjustments to Operating Revenues and Expenses

1. Rate Case Expenses

IP proposed an adjustment to amortize its incremental expenses for outside services associated with this rate case over a three-year period. In the Stipulation, Staff and IP stipulated that a three-year period should be used for amortization of the rate case expenses. In addition, Staff witness Michael McNally proposed that a portion of the fees paid by IP to its cost of common equity witness, Ms. McShane, should be disallowed. In the Stipulation, IP stipulated with Staff to this adjustment.

2. Pension Expense

IP's estimated pension expense as calculated by its actuary constitutes a significant increase over its actual 2003 pension expense. IP proposed an adjustment to increase operating expenses by the portion of the pension expense increase allocated to the gas utility. While no party objected in principle to this adjustment, AG/CUB witness Effron and Staff witness Pearce noted that a portion of the adjustment should be capitalized reflecting that a portion of annual pension expense is charged to construction. IP agreed that a portion of the pension expense adjustment should be capitalized. In the Stipulation, IP and Staff stipulated to use of a 30% capitalization factor, as proposed by Mr. Effron and Ms. Pearce, for this purpose.

3. Company Use of Gas

IP proposed an adjustment to operating expenses to reflect the cost incurred to purchase gas for use at IP facilities, which is a cost not recoverable through the Purchased Gas Adjustment ("PGA") charge. No party objected to this adjustment.

4. Pass-Through Taxes and Related Accounting Fee

IP reduced operating expenses by the amount of certain pass-through taxes and charges it collects for governmental bodies, including municipal utility taxes, State public utility taxes, the Public Utility Fund assessment, and the energy assistance and renewable energy fund charges. In addition, IP accepted AG/CUB witness Effron's position that in calculating the net revenue requirement on which the required revenue increase from base rates is based, the administrative fee that IP is allowed by statute to add to customer bills and to retain as a fee for billing, collecting and remitting municipal utility taxes should be included in miscellaneous revenues.

5. 2004 Wage Increase Adjustment

IP adjusted operating expenses to reflect the known increases in gross payroll attributable to increases in employee salary levels and other salary adjustments scheduled to occur in 2004 for both union and non-union personnel. In calculating this adjustment, IP removed from the base 2003 payroll costs (i) payroll costs for employees whose positions have been eliminated and (ii) the portion of employee compensation applicable to incentive compensation payments, before applying the 2004 percentage increases.

6. Corporate Franchise Taxes

Operating expenses were adjusted for the portion allocated to the gas utility of an increase in IP's corporate franchise taxes in 2004 over 2003 resulting from a change in law.

7. Retirement of River Bend Facility

As discussed in the Rate Base section of this Order, in 2004 IP retired its River Bend facility. Accordingly, operating expenses were adjusted to remove the portion of maintenance expenses and real estate taxes associated with this facility allocated to the gas utility.

8. Charitable Contributions

Operating expenses were adjusted to incorporate IP's 2003 charitable contributions, which were previously recorded above the line in Account 930.2 but are now recorded below the line in Account 426.1 as the result of a 2003 revision to the USOA. This accounting change was not intended to impact the recoverability of expenses for donations for charitable, social and community welfare purposes in future rate proceedings.

9. Uncollectible Expenses

Test year uncollectible expenses were adjusted to reflect the average of IP's uncollectible expenses for the five-year period 1999-2003.

10. FICA Tax Increase

Operating expenses were increased to reflect higher FICA tax contributions in 2004 over 2003 due to a change in law that increased the amount of employee earnings on which employers are required to make FICA contributions.

11. Donated Services

Operating expenses were increased to reflect the cost of gas and gas distribution services that IP provides to various municipalities at no charge or at discounted prices as franchise consideration under the terms of its franchise agreements. The cost of this free or discounted service is not recovered through the PGA charge.

12. Payments to Severed Employees

Operating expenses were reduced to remove (i) the gas utility-allocated portion of wages paid to employees in 2003 whose positions have been eliminated and (ii) severance payments made to these employees.

13. Revised Gas Depreciation Rates

As described in Section IV of this Order, in this case IP is proposing new gas utility depreciation rates based on a recently completed depreciation study. The overall impact of the new depreciation rates is to lower the annual depreciation expense. IP calculated test year depreciation expense by applying the new depreciation rates to the December 31, 2003 plant balances.

14. Depreciation Expense Related to Plant in Service Adjustments including Retirements

IP increased or decreased test year depreciation expense, as applicable, to reflect the impacts on depreciation expense of the various plant in service adjustments to rate base, including the 2004 capital additions, completed CWIP not classified as plant in service at December 31, 2003, small CWIP projects, advanced metering equipment, plant retirements, the adjustment to the capital cost of the Hillsboro well and other plant-related adjustments described in the Rate Base section of this Order. The depreciation expense adjustments relating to gas plant additions that would be included in rate base prospectively utilized IP's new gas depreciation rates.

15. Company Use of Electricity

Operating expenses were increased to reflect the gas utility-allocated portion of the cost of electricity purchased by IP for use in company facilities. This cost is charged to Account 555, Purchased power.

16. Retirement of East St. Louis Facility

During the course of 2003, IP retired a facility in East St. Louis. Operating expenses were adjusted to remove maintenance expenses and real estate taxes incurred for this facility during 2003 prior to its retirement.

17. Removal of Purchased Gas Costs

The expense for gas purchased to supply customers, which is included in IP's overall test year operating expenses but which is recovered through the PGA charge, was removed from operating expenses, since these purchased gas costs will not be taken into account in determining the revenue requirement to be recovered through base rates.

18. Sales Expense

IP reduced operating expenses by removing demonstration and selling expenses, certain advertising expenses, revenues and expenses from merchandising, jobbing and contract work, and other sales expense recorded in Accounts 911 through 916.

19. Advertising Expense

In rebuttal testimony, IP agreed to accept a portion, but not all, of the adjustments proposed by Staff witness Pearce to remove certain advertising expenses from operating expenses. Ms. Pearce subsequently withdrew a portion of her remaining adjustment. In the Stipulation, IP and Staff stipulated that the balance of Ms. Pearce's proposed adjustment, as shown on Staff Schedule 12.05, should be accepted.

20. Industry Association Dues

In rebuttal testimony, IP agreed to accept a portion, but not all, of the adjustments proposed by Staff witness Pearce to remove certain industry association dues payments from operating expenses. Subsequently, in the Stipulation, IP and Staff stipulated that the balance of Ms. Pearce's proposed adjustment, as shown on Staff Schedule 12.06, should be accepted.

21. Lobbying Expense

Staff witness Pearce and AG/CUB witness Effron proposed adjustments to remove certain "lobbying" expenses from operating expenses. In rebuttal testimony, IP agreed to accept a portion, but not all, of the adjustment proposed by Staff witness Pearce. Subsequently, in the Stipulation, IP and Staff stipulated that the balance of Ms. Pearce's and Mr. Effron's proposed adjustment, as shown on Staff Schedule 12.07, should be accepted.

22. Injuries and Damages

IP accepted the adjustment proposed by Staff witness Pearce and AG/CUB witness Effron to remove from operating expenses the portion of test year injuries and damages expense related to Incurred But Not Reported claims.

23. General Research Expense – EPRI Payments

IP accepted the adjustment proposed by Staff witness Pearce to reduce gas operating expenses by removing from general research expense certain payments made to the Electric Power Research Institute.

24. Correction of Depreciation and Amortization Expense on General and Intangible Electric Plant Allocated to the Gas Utility

In rebuttal testimony, IP indicated that the amount of depreciation and amortization expense on electric general and intangible plant allocated to the gas utility had been overstated. Accordingly, IP adjusted operating expenses to remove the excess depreciation and amortization expense.

25. Interest on Customer Deposits

Staff witness Hathhorn proposed that interest on customer deposits held by IP should be included in operating expenses. IP agreed with Ms. Hathhorn but disagreed with the amount of her proposed adjustment. In her rebuttal testimony, Ms. Hathhorn agreed with IP's calculation of this adjustment.

26. Incentive Compensation and Stock Options Expense

In the Stipulation, IP and Staff stipulated that incentive compensation costs (including the related FICA taxes) and costs for employee stock options incurred during 2003 should be excluded from the computation of the revenue requirement, as proposed by Staff witness Pearce and AG/CUB witness Effron. As noted in the Rate Base section of this Order, a portion of these costs is expensed and a portion of these costs is charged to construction and capitalized. Therefore, the adjustments for incentive compensation and stock option costs entail both a reduction to operating expenses and a reduction to rate base, as reflected on ICC Staff Exhibit 12.0, Schedule 12.02 and on Settlement Schedule 3, respectively.

27. Acquisition-Related Operating Expense Savings

IP proposed to reduce test year 2003 operating expenses by the amount of the expense savings estimated to be achieved through a number of initiatives that are being implemented as a result of IP's acquisition by Ameren and its integration into the other Ameren companies. The amount of this reduction to operating expenses is $8,544,000. IP witness Robert Porter presented information on the operating expense savings that Ameren expects will be realized for IP's gas utility operations due to synergies achieved from the integration of IP into the Ameren companies. The list of projects and cost savings on which this adjustment is based were originally identified on Attachment B to Applicants' Exhibit 47.0 in Docket 04-0294, the proceeding in which the Commission approved Ameren's acquisition of IP. The adjustment amount of $8,544,000 was determined by identifying the projects that will have cost-reduction impacts for IP's gas utility operations, summing the savings expected from those projects, and applying the gas utility allocation factor used for allocating expense items in this case, 30.57%. The adjustment did not incorporate savings from projects that will produce savings solely for AmerenIP's electric operations.

Mr. Porter testified that the expense reduction of $8,544,000 by which gas utility operating expenses are being adjusted in this case are part of the overall $33 million of non-fuel operation and maintenance ("O&M") savings identified on Attachment B to Applicants' Exhibit 47.0 in Docket 04-0294. He pointed out that the Order in Docket 04-0294, in particular Conditions to Approval 20 to 23 in Appendix A to the Order, imposes specific obligations and procedures on Ameren and IP with respect to demonstrating progress towards implementing the projects listed on Attachment B to Applicants' Exhibit 47.0 and, ultimately, reflecting the resulting $33 million of O&M savings in IP's revenue requirement in future electric and gas rate cases. He noted that the Commission should recognize that AmerenIP is proposing to incorporate $8,544,000 of these projected operating expense savings in the calculation of the gas utility revenue requirement in this rate case. In the Stipulation, Staff and IP stipulated to incorporate IP's proposed $8,544,000 O&M expense reduction for acquisition-related savings in the revenue requirement in this case.

28. Relocation Reimbursements

As discussed in the Rate Base section of this Order at Section III.A.18, in the Stipulation IP and Staff stipulated to the use of the "compromise approach" to accounting for relocation reimbursements that was proposed by IP witness Carter and accepted by Staff witness Jones. Adoption of the "compromise approach," which effects a change in the method of accounting for relocation reimbursements, results in a reduction in test year depreciation expense.

B. Overall Conclusion on Operating Expense Statement

Based on the gas utility operating expense statement as originally proposed by IP and the uncontested adjustments to operating revenues and expenses as summarized in Section V.A above, the total gas utility operating expenses for AmerenIP approved for purposes of this proceeding are $99,678,000. This amount includes (i) the additional federal and State income tax expense associated with the revenue increase authorized in this proceeding and (ii) the incremental adjustment to uncollectible accounts expense associated with the revenue increase authorized in this proceeding. The operating expense statement may be summarized as follows:

Approved Operating Income Statement
($ x 1000)

Operating Revenues	$ 138,566
PGA Revenues	-
Total Operating Revenue	138,566
Uncollectibles Expense	3,956
Operation & Maintenance	20,109
Cost of Gas	-
Sales Expense	-

Customer Accounts Expenses	7,382
Customer Service and Info. Expenses	934
Pension Expense	-
Administrative and General Expenses	20,826
Depreciation and Amortization	23,743
Taxes Other Than Income	5,989
Rounding	1
Total Operating Expense Before Income Taxes	82,940
State Income Tax	3,076
Federal Income Tax	13,662
Deferred Taxes and ITCs Net	-
Total Operating Expenses	99,678
NET OPERATING INCOME	$ 38,888

The development of the overall gas utility operating expenses adopted for purposes of this proceeding is shown in the Appendix to this Order.

VI. COST OF CAPITAL AND RATE OF RETURN

Evidence concerning the cost of capital and rate of return was submitted by three parties in this docket, namely, Illinois Power, Staff and CUB. In the Stipulation, IP and Staff stipulated to a cost of common equity of 10.00% and an overall rate of return on rate base of 8.18%. IP and Staff also stipulated to the balances and cost rates for long-term debt, transitional funding trust notes ("TFTN") and preferred stock and the balance of common equity, to be used in calculating the overall rate of return. The balances incorporated in the Stipulated Resolution are as of November 30, 2004, and reflect the reduction of IP's common equity balance resulting from elimination of an intercompany note in connection with the acquisition by Ameren, debt redemptions implemented subsequent to the acquisition through December 1, 2004, and equity infusions by Ameren following the acquisition. Also per the Stipulated Resolutions, the rate of return incorporates an adjustment to eliminate a portion of IP's unamortized loss on reacquired debt that had previously been written off in connection with the deregulation of electric generation, as proposed by Staff witness Ms. Freetly. The overall rate of return of 8.18% is calculated as follows as shown on Schedule 8 to both Appendix A and Appendix B to the Stipulation:

Class of Capital	Amount	Percent of Total Capital	Cost	Weighted Cost
Long-Term Debt	$ 684,908,607	29.70%	6.27%	1.86%
TFTN	$ 350,934,973	15.22%	5.95%	0.91%
Preferred Stock	$ 45,786,945	1.99%	5.01%	0.10%

Common Equity	$1,224,252,958	53.09%	10.00%	5.31%
Total Capital	$2,305,883,483	100.00%		
Weighted Average Cost of Capital				**8.18%**

The Commission notes that the rate of return on common equity and the overall rate of return are both within the range of the recommendations presented by the cost of capital witnesses in this case. The Commission adopts the overall rate of return on rate base of 8.18%, including the capital structure components and cost rates shown above, as fair and reasonable for purposes of this proceeding.

VII. COST OF SERVICE; REVENUE ALLOCATION; RATE DESIGN

A. Allocation of Transmission and Distribution Plant Costs

1. IP's Position

In its direct case, Illinois Power used the Average & Excess ("A&E") demand cost allocation method in its gas embedded cost of service study. Staff, in its direct case, advocated the use of the Average & Peak ("A&P") method. Staff witness Lazare testified at length to the reasons why Staff was supporting the A&P method. Both IP witness Althoff and Staff witness Lazare explained the differences and similarities between the A&E and A&P methods. In general, the "average" component of both methods is effectively determined in the same manner. With the A&E method, customer class non-coincident peak demand is utilized in the "excess" calculation, recognizing that not all customers peak at the time of the annual total delivery system peak, whereas in the A&P method, the class peak coincident with system peak is used in the "peak" portion of the allocation.

For purposes of this case, IP agreed to employ the A&P method, with one modification in regard to the allocation of transmission and distribution plant ("T&D"), namely, to exclude the peak demands of grain drying and asphalt customers from the calculation. According to IP, because the Commission has in recent gas rate cases supported the A&P method as opposed to the A&E method and because the net results in employing the two different cost of service methods are reasonably close, IP agreed to the A&P method. IP provided a comparison of the results in terms of the allocation of T&D costs to the customer classes is as follows:

	Transmission		**Distribution**	
Service Classification	**A&P**	**A&E**	**A&P**	**A&E**
51	52.19%	54.04%	66.15%	67.32%
63	15.38	15.90	18.49	18.78
64	4.72	4.99	5.32	5.55
65	4.31	3.69	3.02	2.51
66	1.53	1.41	0.53	0.49

76	16.12	13.55	6.40	5.23
90	5.75	6.42	0.09	0.12
Total	100.00%	100.00%	100.00%	100.00%

IP indicates that while it believes that on a theoretical basis the A&E allocation method is superior, IP has agreed to use a modified A&P approach in this case due to the recent trend in Commission decisions on this point in gas rate cases and, more significantly, the minimal difference in results produced in the context of this case.

2. Staff's Position

According to Staff, the A&P allocation method most accurately reflects the underlying cost of service. In describing the A&E method, Staff states that one of the two A&E allocator components takes into account average demands for both individual customer classes and for the system as a whole while the second component reflects class and system peak demands, actually the excess of peak demands over average demands. Staff says the average component allocates system average demand by the ratio of average demand for individual classes to the sum of the average demands for all rate classes. The excess of system peak over average demand is allocated according to each class' share of the excess non-coincident demands of all rate classes.

Staff claims there are two key problems with the A&E allocator, its reliance on non-coincident peak demands to allocate the excess component. Staff believes the T&D allocator should incorporate coincident peak demands instead because distribution investment is driven by the need to meet demands when the system as a whole, rather than individual rate classes, reaches its peak. According to Staff, if individual class non-coincident peak demands diverge from the system peak, cost allocation will diverge from cost causation.

Staff also asserts that the excess component incorrectly focuses on the difference between peak and average demands, rather than the peak demands only, to allocate costs. Staff argues that costs are driven by peak demands, rather than the excess of peak demands over average demands, and the A&E's focus on excess demands diverges from cost causation.

The first component of the A&P allocator, average annual demands, is the same as the A&E. According to Staff, the A&P method employs an alternative approach to allocate the difference between system peak and average demands based on class contributions to peak demand, rather than the excess non-coincident peak demands employed by the A&E.

Staff claims the two components of the A&P recognize that transmission and distribution plant investment is driven by two key factors. According to Staff, the average demand component reflects the role of year-round demands in shaping transmission and distribution investments. Staff says the coincident peak component recognizes that the system must be designed to: (1) meet peak demands, not just for individual classes, but for the system as a whole; and (2) meet full peak demands, rather than the excess of peak over average demands.

Staff states that since the A&E allocator was approved more than a decade ago in IP's rate case, the Commission has consistently chosen the A&P to allocate T&D costs for gas utilities. It is Staff's position that the Commission reaffirmed that position this year by choosing the A&P methodology over the A&E methodology for the AmerenCIPS and AmerenUE gas companies (Order, Dockets Nos. 02-0798, 03-0008, 03-0009 (Cons.), p. 98 (October 22, 2003)). Thus, in Staff's view, recent precedent indicates the Commission currently favors the A&P allocator over the A&E method.

Staff indicates that the only advocate of the A&E method following rebuttal testimony was IIEC. Staff argues that IIEC witness Dr. Rosenberg has placed himself in an "untenable" position. Staff claims he cannot support two allocators based on conflicting principles at the same time. Staff says the A&E method he endorses is based on non-coincident demands, while the Coincident Peak allocator he also supports reflects coincident peak demands. Staff claims that the question Dr. Rosenberg fails to answer is whether the allocator for T&D costs should be based on coincident or non-coincident peak demands.

According to Staff, Dr. Rosenberg contends that the peak component contains both average and excess demands and, therefore, the A&P double-counts average demands. Staff says Dr. Rosenberg also criticizes the reliance on average demands to allocate T&D costs, arguing that average demands have no impact on the overall allocation of costs.

In Staff's view, the A&P method does not double-count average demands, instead, it recognizes the two key factors that drive T&D investment: (1) the need to meet peak demands and (2) the role of year-round demands in shaping transmission and distribution investments. Staff argues that the A&P consists of two components that reflect these two concerns.

3. IIEC's Position

Even though IIEC supports the use of the A&E method as originally recommended by IP in this case, with certain modifications, IIEC asserts that this method over-allocates costs to larger customers. According to IIEC, the A&P method ignores completely the economies of scale associated with serving the larger customers. IIEC states that the larger customers are generally served by larger pipes. IIEC claims that when measured on a cost per Mcf of capacity basis, the cost of an eight-inch main is less than one-fifth of the cost of a two-inch main.

IIEC contends that the economies of scale exist even if one takes into account the fact that in some instances higher costs are incurred for the installation of larger diameter mains on a per foot basis when compared to the per foot installation cost of smaller mains. IIEC concludes that the eight-inch pipe is still less costly per Mcf of capacity than a two-inch pipe. IIEC argues that by ignoring the significant economies of scale, the A&E method tends to over-allocate T&D costs to larger volume high-load factor customers such as SC 76 customers. In spite of this over-allocation of costs, IIEC continues to support the use of the A&E method in this case as originally proposed by IP with one exception. IIEC claims IP has misapplied the A&E method in this case by using weather normalized data rather than design day data in the development of its A&E allocator.

IIEC states that the coincident peak and class non-coincident peaks used in the Company's study are both based on normal weather. According to IIEC, the IP system is designed to meet a peak day of 891,580 Mcf; however, IP used a coincident peak of 647,221 Mcf in the implementation of the A&E method in its original cost of service study. IIEC states that IP designed its system of mains for weather of 75 degree days, called a design day, that can be considerably higher than on a weather normalized day or actual weather for 2003. IIEC argues that if the design day demands are not reflected in the allocation process, the resulting allocation will not show the true cost responsibility for the transmission and distribution systems.

IIEC urges the Commission to use the maximum of either the non-coincident demand calculated by IP, or the design day send out for each class, whichever is greater in the allocation of mains under the A&E method. IIEC argues that SC 76, the Transportation Class, is even further above cost than indicated by IP's original study and that the Large Volume Sales Class is actually closer to cost of service and the Small Volume Class further below cost of service than shown in the Company's study. IIEC says the residential class is largely unaffected by this modification.

IIEC says Staff criticized the A&E method because it relies on non-coincident peak demands to allocate the excess component and thus does not consider peak day demand upon which the system is designed, thereby creating a mismatch between cost and cost causation. According to IIEC, while it is true that the system as a whole must be designed to meet peak demand on any given day, the record in this case demonstrates that the Company also considers non-coincident peak demand in the design of its system. IIEC argues that the A&E method does, in fact, consider the coincident peak in its formula. IIEC claims this is because the system excess, as opposed to the class excess, is calculated in reference to the coincident peak. In addition, IIEC asserts that with the exception of a few atypical classes, such as the grain drying and other classes, the difference between the coincident peak method and the A&E results would be without consequence. Finally, IIEC says the Commission has previously approved the use of the A&E method for IP.

IIEC states that Staff also finds it problematic that the excess component of the A&E method focuses on the difference between peak and average demands. IIEC claims that Staff misunderstands the theoretical formulation of the A&E method. According to IIEC, the theory underling the A&E method is that because the peak is bigger than the average, the actual system must be sized larger than a system designed to only meet the average demand. IIEC claims that the A&E method allocates costs in two steps: (1) allocates cost responsibility associated with a system designed to meet average demand only; and (2) allocates the cost responsibility associated with a larger system needed because classes do exceed their average demand.

IIEC argues that while the A&E method over-allocates costs to larger customers, the A&P method produces results that are even further from cost in the allocation of transmission and distribution mains. IIEC maintains that the A&P method double counts peak demand, once in the average demand and again in the peak demand. (IIEC Brief at 11, citing Rosenberg IIEC Ex. 2.1 Sch. 1) According to IIEC, the A&E method counts only the portion of main capacity that has not been previously accounted for in the average demand. IIEC contends that this double counting leads to the A&P method computing a demand to certain customer classes in excess of their total peak demand.

According to IIEC, the A&P method imputes a demand to two of IP's five rate classes in excess of their non-coincident peak demand. IIEC asserts that the A&E method does not impute a demand for any IP rate class in excess of that class' non-coincident demand. IIEC claims that the A&P method, all else equal, allocates more costs to high load factor customers than the A&E method. IIEC says that industrial customers generally exhibit higher load factors than the system average, thus the A&P method allocates more T&D costs to industrial customers. In IIEC's view, it would be incongruous to adopt a method that imputes demands to customer classes that are in excess of their maximum demands on the system whenever they occur.

IIEC argues that the A&P method as originally proposed by the Staff wrongfully presumes that an increase in annual throughput without an increase in peak day demand will produce an increase in the cost of mains. IIEC claims that the A&P method allocates greater T&D costs to a customer who uses more gas in non-winter months but does not increase its peak day usage.

Use of the A&P method would, in IIEC's view, aggravate the problem of over-allocation, of T&D costs to larger customers, present in the A&E method. Therefore, IIEC supports IP's original proposal to use the A&E method for allocation of transmission and distribution mains and opposes the use of the A&P method for that purpose.

According to IIEC, while the A&P method and the A&E method produced similar results for most rate classes, for the SC 76 class, the A&P method allocates 20% more transmission main and 20% more distribution main costs to the SC 76 rate class than does the A&E method. IIEC argues that the A&P method and the A&E method do not produce similar results for the SC 76 rate class. IIEC contends that given the A&E method and A&P method produce similar results for all rate classes except SC 76 and the A&P method over-allocates transmission and distribution mains to the SC 76 class, the Commission should adopt the A&E method in this case consistent with its order in the last IP rate case and consistent with cost of service principles. IIEC asserts that adopting the A&E method will benefit SC 76 customers because it will produce a result that is more reflective of their cost responsibility and it will not harm other customers because for those other customers, the results of the A&E method and the A&P method are similar.

According to IIEC, it is not surprising that IP would consider such an over-allocation of T&D costs by the A&P method to be "reasonably close" to the A&E method since IP is not required to pay the resulting rates. IIEC suggests IP would not be as sanguine in its view of what is "a reasonably close result" if the Commission were to find that 20% of IP's investment in the Hillsboro Storage Field was not used and useful and should be removed from rate base on the theory that reflection of 80% of the investment in rates was "reasonably close" to 100%.

IIEC maintains that Commission is free to use, and should use, the A&E method without significantly impacting the other customers classes. IIEC contends the A&P method and the A&E method are reasonably close for all rate classes, except SC 76.

According to IIEC, IP implies that because the SC 90 customer in the IIEC intervention group would receive a decrease in its allocated share of T&D costs under the A&P method, as opposed to the A&E method, it is somehow appropriate to use the A&P method for the allocation of mains. IIEC states that SC 90 Contract Service is not subject to a rate increase or decrease in this proceeding and that SC 90 is a contract rate which is based on the alternative source of gas transportation service available to the customer, not the cost of serving the customer. IIEC argues that as a result, it may be presumed to be less than Rate SC 76. IIEC also claims that, for the SC 90 class, the coincident peak is significantly less than the non-coincident peak. IIEC asserts that as a result, because the A&P method relies on coincident peak and the A&E method relies on non-coincident peaks, the A&E method would allocate more T&D costs to the SC 90 class. IIEC also states that the SC 90 customer referenced by IP also takes service under SC 76.

In response to Staff's reliance on recent Commission "precedent" as support for adoption of the A&P method, IIEC argues that the Commission's decisions are not precedential. IIEC also contends that the Commission reached its conclusion in the AmerenCIPS/AmerenUE cases based in part on the fact that it had previously approved the use of the A&P method for those utilities. IIEC states that in the current case, the Commission has previously approved the use of the A&E method for IP. IIEC claims that to the extent the Commission believes its prior determinations are in fact precedential, the precedent for IP supports the adoption of the A&E method.

According to IIEC, the allocation method selected in the AmerenCIPS/AmerenUE cases apparently had an impact on the smaller classes. IIEC says CUB vigorously contested the method for allocation of T&D mains in that case. IIEC states that in this case, the record shows the adoption of the A&E method, instead of the A&P method, will have little impact on any customer class other than the SC 76 class and that the impact on the SC 76 class is highly detrimental. IIEC also maintains that the double counting of the average demand inherent in the A&P method adversely impacts the very customers who provide numerous jobs in the IP service territory at a time when the service area has lost over 4,000 jobs. IIEC contends that the AmerenCIPS/AmerenUE Order fails to disclose the presence of any similar evidence in that case.

IIEC further argues that in the AmerenCIPS/AmerenUE cases, the Commission was not informed that because the contribution of the average demand is already included in the average component of methods that consider average demand, it is illogical and unreasonable to develop an excess or full demand component which again accounts for average demand.

In response to Staff's argument that the A&P method does not double count, IIEC claims this argument is without support in the record and is contradicted by the testimony of Dr. Rosenberg. IIEC asserts that Dr. Rosenberg's testimony on this issue was unrefuted and unrebutted by Staff, which did not to present any testimony in reply to Dr. Rosenberg and conducted no cross-examination of Dr. Rosenberg. IIEC further asserts that Staff initially agreed that it was illogical and unreasonable to count the average demand once in the calculation of average demand and then again in the calculation of any excess or full demand for the demand allocator used to allocate T&D mains.

IIEC also disputes Staff's assertion that Dr. Rosenberg has placed himself in an untenable position by allegedly supporting two allocators, based on conflicting principles, at the same time. IIEC claims that contrary to Staff's suggestion, Dr. Rosenberg was not supporting the use of two allocators based on conflicting principles at the same time, instead, he was suggesting that if the Commission wished to accept Mr. Lazare's position that the system design is exclusively the function of coincident peak demands, then the Commission may wish to use the coincident peak methodology.

In reply to IP's suggestion that Dr. Rosenberg used incomplete data in his analysis and failed to account for the fact that mains are installed to serve all customers, IIEC claims that IP ignores the point of Dr. Rosenberg's testimony on this issue. According to IIEC, his point was not to recommend that T&D mains be allocated differently than recommended by IP in the context of the A&E method, but to show that the A&E method, as used by IP, over-allocated the cost of mains to T&D customers because it failed to consider economies of scale. IIEC says IP does not refute or dispute this point. IIEC states that Dr. Rosenberg did not recommend that the A&E method be modified to incorporate the economies of scale that it failed to consider. IIEC reiterates that Dr. Rosenberg's point was that the A&E method, as applied by IP, over-allocates the cost of T&D mains to large customers and the A&P method is even worse.

4. BEAR's Position

According to BEAR, all of the proposed allocations have been flawed by how IP has defined "average" use, causing capacity costs to be over-allocated to grain dryers.

BEAR argues that IP's proposed SC 66 rates, however, do not reflect the relative costs and benefits of providing service to grain dryers. BEAR asserts that a properly conducted cost of service study would show that the cost of service to grain dryers is considerably smaller than the cost of service of customers with similar size, but with a usage pattern that includes the use of gas during IP's system peak. BEAR contends that IP's cost of service study does not reflect the benefit provided by grain dryers because it calculates the demand costs of SC 67 and SC 68 differently from the calculation it uses for all other customers.

BEAR says that while IP claims it is not assigning SC 66 customers any peak costs, a review of the company's cost of service study shows that it is attempting to recover peak costs from grain dryers through the "back door" by increasing the "average" use component of the A&P cost allocation method. BEAR states that while IP adopted the Staff's proposal that it allocate demand based on the A&P method, it changed the method for SC 67 and SC 68.

BEAR claims that for all other customer classes, IP calculated average use by dividing total annual use by 365 yet, IP calculated average use for SC 67 by dividing total annual use by 61. BEAR states that IP also calculated the average use for SC 68 by dividing total annual use by a figure less than 365. According to BEAR, IP modified its cost of service study in this manner because 90 percent of grain dryer use occurs within 61 days of the year. In BEAR's view, while that may be true, SC 66 customers should receive a lower allocation of storage, transmission and distribution costs because they have zero use on peak days. BEAR believes that if grain dryers impose negligible demand costs on IP, then their rates should reflect that fact. BEAR claims that by changing its method of calculating average use for current SC 67 and 68 customers so that they would continue to pay for storage, transmission and distribution costs, IP engaged in end result rate making.

BEAR suggests that IP adjusted its cost of service study to obtain the result it wanted – forcing grain dryers to pay demand charges based on storage, transmission and distribution costs that they do not impose on IP. BEAR claims that IP created the exact type of subsidy its own witness warned it to avoid. It is BEAR's position that if a consistently applied A&P method results in grain dryers paying smaller demand charges it would be because they should pay lower demand charges. BEAR contends that IP's manipulation of its cost of service study was an improper attempt to avoid the inevitable and fair result of a consistently applied analysis.

BEAR says IP's defense for its use of a separate cost of service calculation for SC 66 is that it does not build its transmission and distribution system to meet its system peak. According to Ms. Althoff, IP sometimes builds a distribution system in an area to meet a peak at a time other than the system peak. BEAR contends that Ms. Althoff's argument ignores the fundamental fact that IP does not need to build additional transmission or distribution plant to serve grain dryers, because the system that is built to meet the winter peak has enough room on it to serve the grain dryers fall peaking load. According to BEAR, if the system is serving multiple customers, it must be sized to meet the coincident peak of the multiple customers, which will almost always be similar to the system peak. BEAR asserts that if there are any mains that are sized to meet the fall peak of grain dryers, this will be an exception to the rule.

BEAR claims the exception to the above would be where some plant, close to the customer, was sized to meet the customer's peak. According to BEAR, when IP adds local plant in order to serve a large grain dryer, it should have computed that the customer's load will produce enough revenue to recover these investment costs, and may have required a contractual commitment from the customer before making large facilities investments. BEAR says that IP's Rules, Regulations, and Conditions to Gas Service specify that IP need not provide free gas distribution main to a customer if the cost of the extension is less than 1½ times the annual revenue from customers who would take service from the extension unless the customer provides a deposit equal to the deficiency.

According to BEAR, when asked to identify every instance where it built transmission or distribution plant to meet the non-coincident peak of customers, IP was able to identify only two locations where it made such an investment. BEAR asserts that in both cases, the customer made financial contributions to the expansion of facilities to serve them. It is BEAR's position that IP's modification of the A&P method thus results in a double recovery of such investment – first from the affected customer and second from all SC 66 customers.

BEAR maintains that IP's "manipulation" of its cost of service study caused proposed Rate SC 66 customers to pay far in excess of their fair share of demand costs. BEAR claims that IP has designed the rate in such a manner that large numbers of grain dryers that are eligible for SC 66 would be better off with one of IP's other rates even though, unlike other customers with similar annual usage, they have zero demand on peak. BEAR asserts that since distribution capacity costs are slightly more than half of the total distribution costs requested by the Company, the misallocation of those costs has a significant impact on class cost of service.

BEAR recommends that if the Commission chooses to allocate the revenue increase on the basis of a cost of service study, IP should be required to modify its allocation of costs to SC 66 using the same definition of average that is used for other customers, using the general method for allocation of capacity costs approved by the Commission. BEAR claims this will better reflect the true cost of service and will eliminate the cross subsidies grain dryers would be forced to pay to other customers if the current cost of service study were utilized as a basis for allocation. BEAR believes that this simple change in IP's cost of service model would recognize the benefit grain dryers provide to the system by not using gas on the coldest days. BEAR says it will also assist in bringing the cost of service-based rate for SC 66 much closer to conformance with the rate continuity guidelines BEAR has recommended.

5. IP's Reply

According to IP, BEAR's argument is that customers taking service under SC 66 contribute absolutely nothing to the peak and, therefore, costs are allocated to this customer group in an amount greater than they should otherwise be. IP states that these customers do not use the system day in and day out by an equal amount, instead, the vast majority of their usage, about 90%, is likely to be for a specific number days in the year, 61 days for grain drying customers and 184 days for asphalt customers. IP argues that expanding the "average" to the entirety of the year, 365 days, as BEAR suggests, means in effect that they would be using less storage, transmission and distribution, which is not the case, and which is not supported by any events in the record.

IP argues that during the fall, the seasonal use customers rely heavily on the transmission, distribution and storage systems of the Company. IP maintains that the average demand component reflects the role of year-round demands in shaping the transmission and distribution investments. It is IP's position that to do as BEAR suggests has the effect of allocating a substantially reduced amount of these costs to SC 66 customers, to the detriment of all other customers.

According to IP, the "average" portion of the A&E and A&P methods assumes that customers consume gas at a 100% load factor. IP says the seasonal use customers do not use gas consistently for 365 days a year. IP claims that to average SC 66 customers' usage over the entire year would violate the "spirit" of the "average" allocator, whether the A&P or the A&E method is used.

IP also disputes BEAR's assertion that IP's cost of service study results in a double recovery of certain investment. IP argues that this is not true because when contributions are made, rate base is reduced. IP says the capacity-related costs allocated to a class are for the recovery of the investment that is required to lead up to the customer's line extension, that is, infrastructure net of the customer's contribution.

According to IP, distribution planners must ensure that delivery systems can adequately serve customers' demands throughout the year, and they do this by checking that distribution systems are large enough to serve the combined space heat and non-space heat loads of customers throughout the year. IP says it will still be planning for the delivery system as if grain dryers, and other non-space heat customers, will be using gas on days coincident with space heat customers' use at 20 degrees. IP claims that the uniqueness of a temperature threshold in SC 66 has given rise to a unique allocation of mains cost. IP argues that if it were required to include in the average allocator, days in which SC 66 customers use no gas, such a requirement would fail to recognize that these customers indeed compel the Company to run separate reliability planning models for grain dryers in order to ensure system reliability. It is IP's position that its average allocator provides a better link between the planning criteria used in evaluating system reliability and cost of service.

IP also disagrees with IIEC's proposed A&E allocator for allocating the cost of mains. IP claims that the $9.45 per foot cost for 12-inch steel pipe proxy relied on by IIEC witness Dr. Rosenberg was faulty because, in part, he relied on a data request response which on its face stated the information therein would not support the entire cost associated with mains. IP also contends that Dr. Rosenberg completely ignored the fact that mains are common to all customers, so that for him to only incorporate a subset of costs associated with the ten largest customers in developing his arguments was improper. IP claims that IIEC's argument that the A&E method ignores completely the economies of scale associated with serving the large customers is premised on data regarding ten customers.

IP further asserts that Dr. Rosenberg's $9.45 per linear foot measurement is not even an adequate proxy with regard to the specific costs incurred to serve these ten customers. IP argues that, in effect, that Dr. Rosenberg used a system-wide average cost, which by definition is a cost that can be attributable to some degree to each customer, but he then used a specific length associated with these customers in developing the $9.45 per foot unit cost associated with the subject main.

According to IP, steel pipe is capable of carrying higher pressures and steel pipe is generally needed for larger load customers because capacity is a factor and is needed to handle the larger throughput. P claims that main deliverability is based on pressure rating and carrying capacity, which, in IP's view illustrates that larger volume customers require more expensive pipe.

IP argues that IIEC has employed a direct assignment method in support of its position. IP recommends that the Commission disregard this "hybrid" allocation, which, in IP's view, is an aberration of the A&E method.

6. Staff's Reply

Staff says that while IIEC recommends use of the A&E allocator, IIEC qualifies its support for the A&E by stating that the allocator it prefers is the coincident peak ("CP") method. According to Staff, IIEC's support of both the CP and A&E allocation methodologies presents a problem because the two allocators are based on conflicting principles. Staff says IIEC's preferred allocator, the CP, allocates costs according to the demand of each class at the time of the system peak demand. Under the CP methodology, a class that peaks on a day other than the system peak day is still allocated costs based solely on its demand at the time of system peak. Staff states that the A&E methodology, on the other hand, bases allocations on the individual classes' peak days, whether or not they coincide with the system peak day.

Staff says IIEC raises the issue of "double-counting" of average demands in the allocation of T&D costs first to justify the A&E allocator and second, to discredit the A&P allocator. For the A&E allocator, IIEC claims that this allocation methodology avoids the double-counting problem. According to Staff, IIEC asserts that the A&E allocator appropriately considers only average demands for one component and the difference between average and peak demands for the second component. Staff says IIEC reaches a contrary conclusion concerning the A&P allocator, arguing that the A&P allocator double-counts average demands by including them in both the average and the peak components. It is Staff's position that the A&P allocator does not double-count average demands, instead, it recognizes the two key factors that drive T&D investment: (1) the need to meet peak demands, and (2) the role of year-round demands in shaping transmission and distribution investments. Staff argues that the A&P allocator consists of two components to reflect these two concerns.

Staff asserts that IIEC opposes the A&P method because it allocates more costs to its clients. In Staff's view, this rationale falls short of the just and reasonable standard employed by the Commission.

Staff also disputes IIEC's argument that the A&P allocator wrongfully presumes that an increase in annual throughput without an increase in peak day demand will produce an increase in the cost of mains. Staff contends that the purpose of the allocator is to allocate embedded, historical costs that have already been expended, rather than future costs that may or may not be incurred. Staff also claims that it is not evident that demands at the time of peak will produce an increase in the cost of mains. According to Staff, if spare capacity exists, then the system can absorb peak demands without an increase in costs.

7. Commission Conclusion

In this proceeding, IIEC recommends use of the A&E method for allocating T&D plant costs while Staff advocates the use of the A&P allocation method. IP, while claiming that the A&E method is theoretically superior, supports the A&P method in this case because it believes the two methods produce similar results. Among other things, BEAR objects to the manner in which IP computed the average component of the A&P allocator for seasonal customers.

The Commission first observes that it is necessary to allocate T&D plant costs among the various customer classes because direct assignment of cost responsibility is not possible. Thus, in the Commission's view, it is unlikely that any allocation methodology will be perfect. Instead, the goal is to select an allocation methodology that is most likely to be reflective of cost causation and produces fair and reasonable results.

Descriptions of the A&E and the A&P methodologies, as well as the parties' comments on the methodologies, are stated above. Having reviewed those descriptions and arguments, the Commission finds the A&P allocation method superior to the A&E methodology for purposes of allocating T&D plant costs. While the IIEC argues that the A&P method improperly double counts average demand in allocating T&D plant costs, the Commission believes that when allocating T&D plant costs an emphasis on average demand is appropriate. The record demonstrates that the A&P method relies upon class average demands and class coincident peak demands, which by definition are numerically larger than the associated averages. Both methods rely on average demands and, in the Commission's view, an allocator that incorporates class coincident peaks better reflects cost causation than one that incorporates "excess" non-coincident peak demands.

The record indicates that the primary factors driving T&D plant investment are the need to meet peak demands and the need to meet year round demand. The record also indicates that the cost of installing T&D plant does not increase proportionally as the size of the T&D plant installed increases. Contrary to IIEC's assertions, the Commission believes that A&P allocation method, with its emphasis on average usage, adequately recognizes the economies of scale associated with serving larger customers. In the Commission's view, these facts support the use of the A&P method rather than the A&E method for allocating T&D plant costs. Also, the Commission finds superior, the emphasis on coincident peak demand found in the A&P method rather than the emphasis on non-coincident peak demand found in the A&E method.

Finally, the Commission finds unconvincing IIEC's argument that both the A&E and A&P method result in excessive T&D plant costs being allocated to large volume customers. The record demonstrates that the data upon which this assertion is based is flawed. Additionally, as noted previously, the reason underlying the need to select an allocation factor in this case is that it is difficult if not impossible to directly assign among various customer classes the costs associated with T&D plant. It appears to the Commission that IIEC is suggesting the cost of T&D plant attributable to large users is known and IIEC is endorsing an allocation factor consistent with these known costs. The Commission rejects this suggestion.

The Commission will next address BEAR's assertion that the A&P allocation methodology utilized by IP and Staff is flawed due to the manner in which the average portion of the allocator is computed for seasonal use customers. The record shows that the average demand component of the A&P allocator for most customer classes is calculated by dividing the class coincident peak demand by 365 days. For grain drying customers, the average demand component of the A&P allocator is calculated by dividing the class coincident peak demand by 61 days and for asphalt customers the denominator is 184 days. BEAR has recommended that in the event the Commission adopts IP's A&P allocation methodology, it require IP to calculate the average component using 365 days as the denominator for all customer classes.

Having reviewed the record in its entirety, the Commission must reject BEAR's proposal that average demand component of the A&P allocator use 365 days as the denominator for all customer classes. The Commission adopted the A&P allocator, in part, because it properly reflects the fact that one of the primary factors driving T&D plant investment is need to meet year round demand. The Commission believes that because of the different usage patterns among customer classes, universally adopting 365 days as the denominator in calculating the average demand component of the A&P allocator would diminish the effectiveness of the A&P method to properly allocate T&D plant costs.

While the record of this case does not support BEAR's proposal, the Commission believes that conceptually, BEAR has raised an interesting issue. Further, the Commission notes that IP stated that the average component of the A&E and A&P method assumes that customers consume gas at a 100% load factor. (IP Reply Brief at 74) Clearly this is an unreasonable assumption for most customer classes. Thus, in the event IP proposes to use a denominator other than 365 days in the denominator of its T&D plant allocator in its next natural gas rate case for any group of customers, the Commission directs IP to address in its direct testimony the possibility of using denominators less than 365 days for classes other than the seasonal use class.

B. Allocation of Cost of Services

Another cost of service issue raised in this proceeding relates to allocating among the various customer classes the costs of services connecting customer premises to the gas system. Services are typically included in the category of customer-related costs. Customer-related costs normally include capital investment associated with metering equipment and service connections as well as expenses for meter reading, billing, collecting and accounting. Both Staff and BEAR raised objections to IP's proposed cost of service allocator for services.

IP's original proposal for allocating the cost of services for its 413,449 retail customers was based on a sample of 16,273 service lines. Those lines were divided up by pipe size and material (steel or plastic) and unit costs were estimated for each. The Company then factored in the number of customers and average service line length for each class to generate an overall cost of services for each class. These costs provided the foundation for the Company's original services cost allocator.

1. IP's Position

According to IP, based on concerns expressed by Staff witness Lazare and BEAR witness Smith, IP witness Althoff performed an additional review of the services allocator. IP asserts that older services data tracked in the Company's system did not record a diameter size when the corresponding services were installed; as a result, because the size of the services were not tracked, these services were placed in the "zero" size category. IP claims that more recently installed services are now categorized by size. IP states that as a result, the Company's revised allocation of services costs relied upon the more recently installed services, which were categorized by size, to reallocate the older "zero" size services. It is IP's position that the reallocation of the "zero" size services takes into consideration all services installed, both steel and plastic, which should resolve certain of the Staff and BEAR concerns.

IP contends that the results of its revised services allocator are fairly consistent with the information that IP provided to the United States Department of Transportation ("USDOT"). IP says Staff witness Lazare had testified that the USDOT report showed steel services at less than 40% of the total and plastic services at 60%. IP states that its revised services allocator indicates that 35% of the services are steel and 65% are plastic, which is consistent with not only the information in the USDOT report, but also with IP's records. IP claims that with this refinement, the Staff allocations and the revised Company allocations of total services costs to the customer classes now track fairly closely.

IP claims it has provided a revised services allocator that is cost-justified while Mr. Lazare utilized a simple averaging based on an incomplete data set. IP says Mr. Lazare relied on a unit cost for steel and plastic, added them together and divided by two. He then used the resulting average cost for service pipe sizes of 1-inch or less as the basis for developing size-cost weighting factors. IP states that Mr. Lazare used the size cost weighting factors in the eventual development of the services allocation. According to IP, the only rationale given for averaging the unit cost of steel and the unit cost of plastic is that Staff found the original data set relied upon by IP to be unreliable. IP claims this concern should no longer be a consideration since IP's data set was improved and shown to be reliable in the Company's rebuttal case.

IP says that in developing his services allocator, Mr. Lazare relied in part on information provided by the Company in response to IIEC data request 1.33. IP states that Mr. Lazare relied on the linear feet and gross plant balance information from the data request response. IP asserts, however, that the data request response, which was introduced as IP Cross Exhibit 1, stated that the information provided in the data request response did not include all relevant costs. IP claims the cost data provided in the response to IIEC data request 1.33 do not reflect amounts associated with yet to be categorized main from completed projects, main related costs not directly categorized by main material and size (e.g. valves, fittings, filters, etc.) and pro forma adjustments (e.g. CWIP to In-Service, etc.). It is IP's position that the data request information could not provide the basis for depicting all the costs associated with service allocators.

IP asserts that Staff witness Lazare's averaging method for developing the services allocator is further discredited by a comparison of the relative cost differences between plastic and steel pipe. IP claims that depending on the size of the pipe, the variance in cost between plastic and steel can vary. According to IP, steel is 14 times more costly than plastic with regard to pipe that is 1 inch in diameter; however, steel is only 3 times more costly than plastic when considering 4 inch diameter pipe, and only 1.5 times greater for 6 inch diameter pipe. IP argues that the simple averaging approach supported by Mr. Lazare increased the cost assigned to the residential customer class.

IP also claims that because Mr. Lazare's approach allocates no services cost to the SC 90 customer class, it is flawed. IP also complains that under Mr. Lazare's services allocator, the SC 76 class, which has 191 customers, would only be allocated 0.2% of the total service costs whereas under IP's allocator 0.46% of the services cost would be allocated to this class.

IP claims that Staff ignores the Company's response to Mr. Lazare's data request PL 2.02, which was discussed by IP witness Ms. Althoff in her surrebuttal testimony. According to IP, that data request response provided the breakdown between material and labor cost associated with both steel and plastic pipe, based on the various pipe diameters used. IP asserts that this information shows that labor cost is the significant driver in determining the total cost, and that steel is more costly than plastic. IP claims the response to another data request, PL 4.09, explained that steel is more costly than plastic because steel pipe needs to be cathodically protected. IP says this response also explained why the labor costs associated with installing steel are greater.

IP argues that while Mr. Lazare may have questions about the underlying numbers that support IP's revised services allocator, he has no facts and made no effort to raise these questions in his rebuttal testimony, nor did he attempt to refute the basis for the numbers that support IP's revised services allocator.

IP states that BEAR witness Smith expressed concerns about the relative costs of plastic and steel pipe and the sizes of the pipes in relationship to load. IP claims, however, that Ms. Smith ignored the fact that pipe selection is based on the amount of gas delivered to the customer and the pressure at which customers are served, and that higher-pressure customers require steel services, which are more costly that plastic pipe with respect to both material and installation costs.

According to IP, BEAR witness Smith complained that IP's use of current costs as a basis for allocation would not be correct. IP asserts, however, that the use of current costs provides a better basis for allocating costs to customer classes because it eliminates the varying impacts of inflation on different plant items that is present when historic costs are used. IP also claims that under the Federal Energy Regulatory Commission's Uniform System of Accounts, IP is only required to record plant and expenses by account without a customer class designation. IP further asserts that the current cost approach is consistent with the Commission decisions in IP's delivery service tariff cases (Dockets 99-0134 and 01-0432) where the Commission approved the use of current costs for electric service drops, as well as meters, to allocate the embedded costs of those plant items.

2. Staff's Position

Staff states that in rebuttal, Company witness Althoff acknowledged problems with its originally proposed allocator and sought to explain how they arose. Staff says she contended that the problem lay with service lines the Company originally classified as having diameters of "zero" inches that were not appropriately factored into the allocation process. According to Staff, Ms. Althoff then "corrects this problem" in a revised allocator she offers in rebuttal. Staff states that allocator revises the distribution of services between steel and plastic but maintains the assumptions of IP's original allocator that steel is far more costly than plastic.

Staff asserts that in rebuttal the Company attempted to support the assumption of significantly higher costs for steel over plastic with the contention that steel prices significantly exceed plastic prices on the current market.

Staff argues that the Company's poor track record on this issue makes it difficult to have confidence in the revised allocators. Staff also expressed concerns about the cost distinctions Ms. Althoff continues to make between steel and plastic service.

According to Staff, in arguing that steel services are more costly, IP focuses solely on the prices of the materials, rather than the much higher installed costs of steel and plastic services, which include capitalized labor. Staff says that for 3-inch pipe, IP explains the $2.63 difference in material prices, but failed to support the remaining difference of $18.55 in the Company's calculation of steel and plastic costs. It is Staff's position that the Company's assumptions concerning price differences between steel and plastic remain largely unsupported.

Staff also argues that IP errs in focusing solely on current prices. Staff states that the large majority of services on the IP system are many years old and the capital cost of those services reflects the material costs at the time of installation. Staff says those costs are not impacted by recent price trends for materials. In Staff's view, the allocation of services should not be solely governed by the current relationship between steel and plastic material costs.

In response to Staff's argument that the Company has not justified its assumptions that steel is significantly more costly to install than plastic, Staff says IP presents a breakdown of the relative costs to install steel and plastic and then identifies specific factors that it claims drives the much higher cost of steel over plastic. According to Staff, the higher costs for steel include the need for cathodic protection and welding; shorter lengths and heavier weight.

According to Staff, IP's argument regarding higher steel labor costs fails to explain why unit costs for plastic are higher than for steel at the distribution level. Staff claims that the labor costs presented by IP do not make sense from a common sense standpoint. Staff states that IP identifies a unit labor cost of $8.10/ft. for ¾-inch steel; $13.89 for 1-inch steel and $13.89 again for 1¼-inch steel. In Staff's view, it is not clear why 1-inch steel should be so much more costly to install than ¾-inch steel given that the costs of installing 1 and 1¼-inch steel are the same. Staff contends the discrepancies are more pronounced for plastic with the installation costs range from $2.00 to $2.78 per foot between ½ and 2-inch pipe. Staff says that for 3-inch pipe, the installation costs jumps to $9.51 per foot. Staff contends that IP failed to explain why labor costs jump so dramatically. Staff believes that these discrepancies undermine confidence in the accuracy of IP's services cost estimates.

According to Staff, the Company's assumption that steel costs far more than plastic is not supported by data concerning distribution level costs. Staff says the question remains why plastic pipe should cost more at the distribution level, but steel costs far more for pipe on the customers' premises. Staff claims that IP focuses solely on material prices and fails to consider other costs associated with the installation of steel and plastic services. In Staff's view, the Company's assumptions concerning differences in the installed cost of steel and plastic remain largely unsupported.

Staff says that in an effort to justify its use of current costs to develop an allocator for historical services costs IP argues that the practice eliminates concerns about varying inflation impacts for different type of plant. Staff argues that the Company has failed to establish that the current relationship between steel and plastic costs existed during the historical period when services were installed. Staff states that if the cost relationships between steel and plastic differed in the past then the use of current costs will distort the allocation process. In response to IP's claim that similar allocators have been used in previous cases on this issue, Staff asserts that the use of a deficient services allocator in the past should not permit IP to use this same deficient approach in current and future cases.

It is Staff's position that the Company's revised allocator continues to rely on unreliable data and flawed assumptions. Staff claims that IP's revised services allocator would be a step back rather than an improvement upon the Staff proposed allocator.

In response to IP's attack on Staff's proposed services cost allocator, Staff claims it is a gigantic leap for IP to conclude that the exclusion of main project costs yet to be categorized or pro forma adjustments renders this distribution cost data meaningless. According to Staff, IP provided no evidence to support its suggestion that the addition of these items would undermine the general conclusion concerning relative steel and plastic distribution line costs.

Staff contends that IP's own data shows existing plastic distribution pipes, excluding pro forma adjustments, have higher unit costs than steel pipes. In Staff's view, the available distribution cost data conflicts with the data provided for services and calls into question the reliability of the data supporting IP's proposed allocator.

Staff disputes IP assertion that that Staff's approach allocates no services cost to the SC 90 customer class. Staff claims that its approach does allocate services costs to SC 90 but the amount allocated is quite small. Staff states that SC 90 consists of a single customer with 76 ft. of 2-inch service lines on a system with 38,954,266 feet of service lines. According to Staff, with the values in the cost of service study presented in thousand dollar increments, the amount allocated to SC 90 rounds to zero. Nevertheless, Staff says its study does allocate costs to SC 90, contrary to IP's claim.

3. BEAR's Position

BEAR states that although IP's cost of service study was based on embedded costs, IP used current costs to allocate service installation costs. BEAR contends that this mixture of embedded and current costs skewed the results of IP's cost of service study and made it appear that it costs more to serve most general service customers, including grain dryers, than a consistent cost study would show.

According to BEAR, the purpose of allocating existing plant investment is to reflect the relative amount of dollars that have been invested to serve each class. BEAR says such level of investment reflects historic costs, not current costs. BEAR asserts that current costs are only a reasonable proxy for historic costs when the relationship between the costs remains the same. BEAR claims that if most existing plant costs resulted from a time when cost relationships between materials were different from the present, using current costs as a basis for allocation would not be correct. BEAR contends that if steel pipe costs much more relative to plastic pipe than it did when most pipe was installed, and the Company is using this current cost ratio to allocate, the revised service plant allocation is not accurate.

BEAR states that customers are using primarily old pipe, and the Company's rate base reflects primarily old pipe. BEAR recommends that IP rerun its cost of service methodology using all historic costs to allocate customer costs rather than a mixture of historic and current costs.

BEAR agrees it is sometimes appropriate to use current costs, if the cost relationship between items remains the same. BEAR contends, however, that IP has mixed and matched historic and current data and has done so for items that do not have the same historic and current cost relationship. It is BEAR's position that to the extent that steel pipe currently costs more relative to plastic pipe than the cost relationship when most pipe was installed, IP is calculating an incorrect service plant allocation.

BEAR says it is important to understand the purpose of allocating existing plant investment. According to BEAR, IP has conducted an embedded cost study in which it is attempting to identify the relative amount of dollars that have been invested to serve each class. In BEAR's view, it is irrelevant that inflation has affected prices for steel pipe more than other items, that IP reports current costs to FERC or that IP uses current costs in its delivery service tariffs. BEAR contends that the embedded cost of service study is allocating embedded costs, not the costs that would exist if all customers had new equipment purchased at current costs.

4. CUB's Position

In its brief, CUB states that it agrees that even though IP's revised services cost allocation methodology does not severely affect residential customers, the Commission should base its decision on the soundness of the numbers, so IP's proposal should be rejected and the Staff's methodology for allocating pipe by size should be adopted.

5. Commission Conclusion

As the Commission, previously observed, allocators are sometime necessary when direct assignment of cost responsibility is not possible. As with T&D plant costs, service costs cannot be directly assigned and an allocation method is needed. Again, because it is unlikely that any allocation methodology will be perfect, the goal is to select an allocation methodology that is likely to reflect cost causation and produce fair and reasonable results.

The results of the two proposed allocation methods for services costs are summarized in the table below:

Service Classification	Staff Direct	Revised Company
SC 51	84.25%	80.23%
SC 63	14.59%	17.01%
SC 64	00.72%	01.70%
SC 65	00.11%	00.30%
SC 67	00.11%	00.28%
SC 68	0.01%	00.03%
SC 76	00.20%	00.46%
SC 90	00.00%	00.80%

(IP Ex. 5.6 at 16-17) While the Commission recognizes that some parties have a vested interest in the outcome of this proceeding and that all parties have the right to argue any position they choose, the Commission is somewhat surprised at the level of argument regarding this issue given the relatively small difference in results. This is even more perplexing given the nature and magnitude of other issues in this case that were originally contested and ultimately settled.

Nevertheless, the Commission will address the merits of the parties' arguments. First, the Commission notes that IP has withdrawn its originally proposed allocation methodology and no discussion of that method or its alleged flaws is necessary.

The record contains essentially two criticisms of IP's revised allocation methodology: 1) IP's stated installation costs of steel and plastic services are illogical and 2) other than differences in material costs, IP failed to adequately explain the differences in installed costs of plastic and steel services. IP, on the other hand, complains that in developing its allocators Staff relied upon a data request response that was not entirely complete and that its averaging approach was overly simplistic.

The record contains data regarding the installed costs of various sizes of steel and plastic services as well as Staff's complaint these stated costs are illogical. However, it is not clear to the Commission why Staff believes these stated costs are illogical or what costs Staff expected or believes would be logical. The Commission is left to wonder if Staff expected a direct relationship between size and cost for both steel and plastic services or some other relationship. Additionally, there is no explanation why Staff's expected relationship would be more logical than IP's stated costs.

Additionally, the record indicates that IP attributed the differences in installed cost between steel and plastic services to the fact steel services are heavier, are shorter in length, and require welding and cathodic protection. It appears that these assertions were not refuted.

Finally, it has been suggested that the using the current cost of services to allocate the embedded cost of services is either inaccurate or inappropriate. As discussed previously, an allocator for the cost of services is necessary because it is not possible to directly assign such costs. Therefore, in this context the argument that such an approach to allocating costs is inaccurate has no meaning. Additionally, the Commission finds nothing inherently inappropriate in allocating the embedded cost of services on the basis of the current cost of services. The Commission finds that using the current cost of services could produce a set of cost allocators that is reasonably reflective of costs various customer classes impose on the system and could produces fair and reasonable results.

As for Staff's method, while it appears that the data underlying Staff's allocators for services costs was not totally complete, it appears to have excluded a relatively small amount of data that would not likely have had a significant impact on the results. Furthermore, while Staff's method for averaging steel and plastic services costs are somewhat simplistic, the Commission observes that developing allocation factors is not an exact science. The Commission finds no merit in IP's suggestion that Staff's method allocates no services cost to the SC 90 class, this is simply incorrect. As for IP's complaint about the result of Staff's allocation of services costs to the SC 76 class the Commission finds this argument to be a result oriented, self-serving argument that deserves no weight.

Having reviewed the record in its entirety, the Commission believes that either Staff's proposed allocation method or IP's revised allocation methodology could, in all likelihood, achieve the stated goals of reasonably reflecting cost causation and producing fair and reasonable results. Additionally, the Commission is somewhat surprised to see that CUB endorses Staff's allocation method even though it would allocate slightly more services costs to the residential rate class than would IP's revised allocation method. Nevertheless, the Commission finds that Staff's allocation methodology should be used for allocating the cost of services in this proceeding. The record shows that while the results of the two methods are quite similar, the Commission concludes that the Staff method should be adopted for purposes of this case based on the evidence in this record and the facts and circumstances of this case.

C. Proper Cost of Service Study

1. IP's Position

IP disagreed with Staff witness Lazare's position that Staff's cost of service model and study, rather than IP's cost of service study, should be used for purposes of this proceeding. IP express concerns with the terminology used in Staff's model, the use of pasted values, and the lack of clarity with regard to certain of the formulas and other input data. IP also complained that Staff used data from IP's model to develop Staff's cost of service results. IP asserts that Staff's model relied on a "hodge-podge of data." IP asserts that this is problematic and will to lead to incomplete and confusing results.

IP claims that while its cost of service model is able to calculate the revenue requirement by function, the Staff model is deficient in this respect. IP asserts that Staff's model is incapable of calculating the revenue requirement by function (i.e., storage, transmission, distribution, services, meters) and by rate class. IP stated that its cost of service model is capable of producing this level of detail which is used in the development of the specific proposed rates for each service classification. IP argues that its cost of service model should be used to produce the final cost of service study to be used in the final interclass revenue allocation and establishment of specific prices, based on the Commission's substantive determinations. IP contends that use of Staff's cost of service model would lead to unintended results.

2. Staff's Position

According to Staff, its cost of service study should serve as the foundation for ratemaking in this case for two reasons. First, Staff claims its study incorporates a more reasonable cost allocation methodology than the Company study. Second, Staff contends that its study is open and accessible, in contrast to IP's cost study, which Staff says raised both confidentiality and accessibility issues.

According to Staff, IP relies on a copyright-protected study from a third party and outside users must sign a confidentiality agreement to receive a copy of the model. Staff states that the copy Staff initially received did not allow full access to the study. Staff claims certain formulas in the study were hidden from the user impeding efforts to determine whether the model did, in fact, produce the claimed results. It is Staff's position that securing a functional study required considerable time and energy that would have been better invested in reviewing the Company's costing and rate proposals in this case.

Staff states that the regulatory process must ensure that the rates customers pay are just and reasonable. Staff claims that to make that determination, regulators and intervenors need full and unimpeded access to the underlying costs that support proposed rates. According to Staff, the "limited and incomplete" cost study initially provided by IP in this case makes it difficult for regulators to meet this objective. Staff argues that the Company's action adds complexity and delay that serve to undermine and compromise the review process. Staff complains that this makes it difficult for Staff to verify that the Company's proposed rates are, indeed, just and reasonable.

Staff asserts that its study offers the advantage of being more straightforward and transparent than the Company study. Staff says no confidentiality statements need to be signed to receive a copy, and the study itself is fully functional with all cells and formulas directly accessible to the user. Staff claims its study facilitates a more open and thorough regulatory process. In addition, Staff claims that its study reflects a more reasonable allocation methodology and it should be used for ratemaking in this proceeding.

Staff recommends that the Commission order IP to present a non-copyright-protected cost-of-service study in future gas cases. Staff asserts that this requirement should not be unduly burdensome considering that other Ameren affiliate gas companies are able to sponsor non-copyrighted cost studies in their rate proceedings.

Staff says IP does not view it as burdensome to require confidentiality agreements to be signed before receiving a cost study. Staff also says IP is not troubled that Staff had to request a second copy to be able to see how the Company study actually worked.

Staff also suggests that the ten weeks available, after it received the version of IP's cost study it desired, is insufficient to effectively perform a full review of the Company's complicated cost study with a "maze of formulas and calculations" consuming almost 2,000 lines of an Excel spreadsheet. Staff says the study must be reviewed thoroughly because it plays a critical role in the case, serving as the foundation for revenue allocation and rate design. Staff argues that limiting the available review time impedes Staff's ability to verify the results obtained.

According to Staff, IP attempts to put the onus on Staff for the delay in receiving a fully transparent copy of IP's cost of service study. Staff complains that this is a case of blaming the victim for the problem. Staff contends that if the problem lies with the Company's failure to provide a fully transparent model, then the burden should be on IP, rather than Staff, to devise a solution.

Staff says IP argues that a model with hidden formulas does not constitute an incomplete model because it contains all the cost data required to develop a cost of service study. In Staff's view, if the only purpose of the model was to transform a set of inputs into outputs, then this argument might have some validity. Staff acclaims that if the purpose is to verify the accuracy of the results, then a model with hidden formulas falls short of the mark.

Staff says IP also attempted to justify the use of the Company's study because it satisfies the Part 285 minimum filing requirements. According to Staff, just because the Company meets the minimum filing requirements that does not guarantee its proposals will be adopted in the Commission's final order. Staff asserts that IP must meet the Commission's just and reasonable standard for ratemaking and IP's study falls short.

Staff says that in past proceedings, Staff has "jumped through all the necessary hoops" to secure copies of the study without raising objections to the Company's approach. Staff says it has found the experience to be burdensome and has concluded that an alternative approach is necessary. Staff believes its concerns about the Company's approach should be considered on their merits and not solely on whether Staff has made similar objections in the past. Staff argues that limiting parties to arguing only their past positions would make it difficult for the regulatory process to develop and evolve. Staff further contends that there is no legal requirement so limiting parties or the Commission, as Commission decisions do not have a *res judicata* effect in later proceedings before it.

3. Commission Conclusion

Having reviewed the record on this issue, it appears to the Commission that neither IP nor Staff has raised significant substantive arguments with the other party's cost of service study. For example, the Commission is not compelled by IP's vague complaint that Staff used a "hodge podge" of data – which was substantially taken from IP's cost of service study. Similarly, IP's complaint about the level of detail produced by Staff's cost of service study does not impress the Commission, as Staff was able to use this output to develop rates for each rate class.

Staff's complaint about the "transparency" of IP's cost of service study is addressed in more detail below, but needless to say, the Commission has previously relied upon cost of service models with similar levels of transparency. Additionally, Staff's assertion that its cost service model study reflects a more reasonable allocation methodology might be more compelling if it were explained more thoroughly.

Finally, the Commission has reviewed the results of the cost of service studies, including Staff Ex. 6.0, Schedule 6.06 and Staff Ex. 16.0, Schedule 16.02. The record indicates that IP's and Staff's cost of service studies produce similar class cost of service responsibilities, particularly with the revisions adopted in IP's rebuttal analysis.

Thus, in the Commission's view, it appears likely that either cost of service model could reasonably be used for purposes of cost allocation and rate design in this proceeding. Nevertheless, the Commission concludes that Staff's cost of service study should be adopted in this case. The transparency concerns, while not dispositive of the issue, are worthy of consideration. Additionally, the fact that the Commission has relied upon the Staff cost of service study in numerous recent gas rate cases favors use of the Staff model. Thus, while it is very close issue, the Commission believes it would best to use the Staff cost of service study as the basis for allocating costs and establishing rates in this proceeding.

D. Issues Associated with Vendor-Supplied Cost of Service Model Used by IP

1. Staff's Position

Staff argues that the Commission should order IP to present a non-copyright-protected cost-of-service study in future gas cases. Staff argues that this requirement should not be unduly burdensome considering that other Ameren affiliate gas companies are able to sponsor non-copyrighted cost studies in their rate proceedings.

Staff further argues that ten weeks is insufficient to effectively perform a full review of the Company's complicated cost study with a maze of formulas and calculations consuming almost 2,000 lines of an Excel spreadsheet. Staff notes that the study must be reviewed thoroughly because it plays a critical role in the case, serving as the foundation for revenue allocation and rate design. Limiting the available review time clearly impedes Staff's ability to verify the results obtained.

Staff takes issue with IP's assertion that Staff was responsible for the delay in receiving a fully transparent copy of IP's cost of service study. Staff argues that this is truly a case of blaming the victim for the problem. Staff believes that if the problem lies with the Company's failure to provide a fully transparent model, then the burden should be on IP, rather than Staff, to devise a solution.

Staff does not agree that a model with hidden formulas does not constitute an incomplete model because it contains all the cost data required to develop a cost of service study. Staff argues that if the purpose is to verify the accuracy of the results, then a model with hidden formulas falls short of the mark.

Staff acknowledges that the Company has provided similar confidential cost studies in past proceedings and Staff has jumped through all the necessary hoops to secure copies of the study without raising objections to the Company's approach. Over time, Staff has found the experience to be burdensome and has finally concluded that an alternative approach is necessary. Staff's concerns about the Company's approach should be considered on their merits and not solely on whether Staff has made similar objections in the past. Limiting parties to arguing only their past positions would make it difficult for the regulatory process to develop and evolve. Further, there is no legal requirement so limiting parties or the Commission, as Commission decisions do not have a *res judicata* effect in later proceedings before it.

2. IP's Position

IP responded to Staff's concerns about IP's use of a copyright protected, vendor-supplied cost of service model and its proposal that the Commission should order IP to present a non-copyright-protected cost of service study in future gas rate cases. IP believes that its cost of service study was presented in this case consistent with the applicable rules. IP acknowledges that a utility may be prevented from providing a working model that it obtained from an outside vendor by virtue of the utility's agreement with that vendor. IP notes that in that event, the utility is permitted to have its vendor enter into an agreement with case participants to provide a working copy of the model to be used for a fixed and limited time period. IP believes that Staff was slow in requesting a copy of the IP model until about six weeks after the case was filed, which was 25 days after other Staff members had sent their initial data requests, and the model was provided after Staff signed a confidentiality agreement.

IP notes that cost of service models supplied by the same vendor that supplied IP's gas cost of service model have been used by IP in the past, this same vendor has required a confidentiality agreement to be signed and, Staff has used this very model in past IP cases. IP believes that in a recent rulemaking concerning Part 285 if Staff had any complaints with regard to the use of an outside vendor, the use of a confidentiality agreement, and whether a cost of service study may have hidden formulas, the time to address these matters was in the context of that rulemaking, and not in this rate case.

IP emphasizes that Staff could review all the inputs of IP's model, make changes and execute alternative scenarios. IP notes that any party that executed a confidentiality agreement, was provided a fully functioning copy of the cost of service study identical to the model IP used.

IP states that it offered to engage in a collaborative effort with Staff and any other interested parties following the conclusion of this rate case to address ways of mitigating Staff's concerns while satisfying vendor requirements with respect to maintaining confidentiality of the cost of service model. However, IP urged the Commission to reject Staff's proposal that IP be required to utilize a non-copyright-protected cost of service model in future cases.

3. Commission Conclusion

The Commission finds, based on the record, that Illinois Power made its cost of service model available to Staff and other parties in this case in conformance with the requirements of recently-amended 83 Ill. Administrative Code Part 285, in particular Section 285.5110. Further, IP's actions in this regard were consistent with what has transpired in previous cases with respect to the use and availability of a vendor-supplied, copyright-protected cost of service study. Additionally, adequate opportunity was provided to interested parties in this case, consistent with the Commission's rules, to access an unrestricted version of IP's cost of service model. The Commission finds that Staff's concerns are not sufficient to reject use of IP's cost of service model in this case, or to require IP to adopt a different model in the future. The Commission encourages IP, Staff, and other interested parties to work together to mitigate the concerns raised by Staff.

E. Development of Rates and Charges - Adjusting Rates to Meet the Final Revenue Requirement

1. IP's Position

Schedule 3 to each of IP Appendix A and IP Appendix B to IP's Initial Brief showed IP's proposed rates and charges in the individual service classifications for the $11,336,000 and $14,227,000 base rate revenue increase scenarios, respectively. IP states that the starting point was the allocation of the overall revenue requirement to the customer classes on an equalized rate of return basis using the cost of service study. Within each class, customer costs (i.e., the costs associated with serving a customer regardless of whether any gas is used, including the meter, service line, regulator, recurring meter expenses and administrative costs of servicing the account), as developed in the cost of service study, were used to develop the proposed Facilities Charges. Delivery Charges and, for the service classifications on which larger-use non-residential customers are served, Demand Charges, within each service classification, were used to recover the remaining fixed costs associated with the customer's use of IP's distribution system.

IP proposes increases to the existing rate elements in its gas tariffs without significant rate design changes from the current tariffs. IP summarizes its proposed rate design, particularly with respect to changes from the rate design in IP's current gas rates.

The Delivery Charges in present SC 51, Residential Gas Service, and SC 63, (non-residential) Small Volume Firm Gas Service, are both declining block rates. IP proposes that the Delivery Charges in SC 51 and SC 63 become single, flat rates applicable to all therms delivered, because all customer costs are to be recovered through the Facilities Charges in these service classifications. IP noted that there was no objection to this proposal.

For SC 65, Large Volume Firm Gas Service, and SC 76, Transportation of Customer-Supplied Gas with Best Efforts Backup, IP developed separate Facilities Charges for each service classification, but the transmission and distribution costs for SC 65 and SC 76 were combined to establish the cost bases for the high pressure and low pressure Demand Charges. The low pressure Demand Charge is based on the cost for the delivery assets (i.e., facilities operated at equal to or less than maximum allowable operating pressure ("MAOP") of 60 psig) required to get to the customer's location plus the cost for transmission delivery assets (i.e., facilities operated at a MAOP greater than 60 psig). The cost basis for the high pressure Demand Charge excludes the cost for the low pressure assets since customers served at high pressure do not utilize IP's low pressure system. Additionally, the SC 65 Delivery Charge recovers a portion of demand costs.

The SC 76 Facilities Charges for customers that would otherwise be served on SC 63 or SC 64 if they took firm supply gas service from IP are equal to the applicable

Facilities Charges under those service classifications. However, for customers with an average daily usage of 1,000 therms or more, separate Facilities Charges are provided in SC 76 for customers with an average daily usage of up to 10,000 therms and customers with an average daily usage of 10,000 therms or more. Additionally, IP is eliminating the Delivery Charge in SC 76 because delivering gas to SC 76 customers does not cause IP to incur a volumetric delivery cost.

SC 66, Seasonal Gas Service, is a new, optional tariff intended to replace existing SC 67, Firm Gas Grain Drying Service, and existing SC 68, Seasonal Gas Asphalt Service. Customers that might find SC 66 attractive will also have the option to take service on any other service classification for which the customer qualifies (i.e., firm supply service on SC 63, SC 64 or SC 65, or transportation service on SC 76). IP initially proposes that SC 66 would include separate Facilities Charges for customers with a Maximum Daily Quantity ("MDQ") or actual use less than a maximum of 1,000 therms per day and for customers with a MDQ or actual use equal to or greater than 1,000 therms per day. However, in response to customer impact concerns expressed by BEAR witness Smith, IP developed Facilities Charges for SC 66 customers delineated between customers served from facilities with MAOP equal to or less than 60 psig and customers served from facilities with a MAOP greater than 60 psig, and with separate Facilities Charges within each of these categories for small, medium and large customers. IP states that it is proposing a menu of six Facilities Charges in SC 66 to better match cost recovery and pricing to the specific characteristics of the individual customers served on this tariff and the facilities that serve them. (Issues relating the SC 66 Facilities Charges, as well as the overall price level and competitiveness of this rate, are addressed in greater detail in Section VII.F below.)

SC 66 customers that purchase system supply gas from IP will be billed the Rider B Gas Commodity Charge under IP's PGA. IP stated that this feature of SC 66 will provide a benefit particularly to grain dryers currently served on SC 67, since SC 67 customers are billed the Rider A Gas Charge, which recovers pipeline demand-related gas supply costs as well as commodity costs, and therefore typically is higher than the Rider B Gas Commodity Charge.

Additionally, under SC 66, customers will be billed a Delivery Demand Charge and the Rider B Demand Gas Charge based on gas consumed on days when average temperatures are forecasted to be at or below 25 degrees Fahrenheit. IP originally proposed that these demand charges be applicable for usage consumed on days when the temperature is forecast to be at or below 32 degrees F., but modified this provision to 25 degrees F. during the course of the case in response to concerns expressed by BEAR. IP noted that BEAR's Initial Brief indicated acceptance of the 25 degree F. threshold. However, SC 66 customers that have provided a contribution to IP for a delivery system improvement to expand capacity to serve the customer's load at times of system peak will be allowed to contract with IP for a Winter Delivery Allowance, which will be an amount of gas the customer can use on days when the temperature falls below the temperature criterion, without incurring a Delivery Demand Charge. Such customers will, however, be billed the Rider B Gas Demand Charge for gas consumed on days when the temperature is forecast to be below 25 degrees F; this is because the Rider B Gas Demand Charge recovers gas supply costs, not delivery system costs.

IP notes that Schedule 3 in each of IP Appendix A and IP Appendix B to its Initial Brief shows IP's proposed rates and charges for each service classification under the $11,336,000 and $14,227,000 base rate increase scenarios, respectively, along with a comparison to the current rates and charges. IP witness Jones explained how the final rates and charges should be established to produce the final revenue requirement allocated to each customer class, if the final revenue requirement is less than the revenue requirement proposed by IP in rebuttal (which both the minimum and maximum revenue increases defined by the Stipulation will be). IP employed these considerations in developing the proposed rates and charges shown on Schedule 3 of IP Appendix A and IP Appendix B attached to the initial brief.

As was the case with respect to the class revenue allocation, IP disagreed with Staff's position that if the final approved revenue requirement is lower than the revenue requirement presented by IP in rebuttal, which Staff used to design the proposed rates presented in Staff's rebuttal testimony, then each of Staff's proposed rates and charges should be adjusted downward on an equal percentage basis to achieve the approved revenue requirement. IP stated that Staff's approach is inappropriate and would disregard the considerable effort the parties to this case have devoted to revenue allocation and rate design issues.

2. Staff's Position

Staff believes the Commission should employ Staff's proposed method of adjusting rates to meet the final revenue requirement adopted by the Commission in this proceeding. Staff proposes to make the adjustment process as simple and transparent as possible. That entails taking the rates Staff proposed in rebuttal and prorating them on an equal percentage basis to produce the revenue requirement adopted by the Commission. Adoption of this approach is predicated on the Commission acceptance of Staff's proposed cost of service and rate design in this case. If the Commission were to request changes in the Staff cost study, Staff explained in rebuttal the additional steps necessary to develop final rates. The Staff proposals in each instance seek to minimize the steps necessary to develop final rates in this proceeding, and to give as clear a picture as possible of what the final rates might be.

In contrast, Staff claims the Company's proposal to adjust rates to the approved revenue requirement is complicated and difficult to follow. Company witness Jones explains in almost two full pages of testimony how the adjustment process would be made. First, the Company would rerun its cost of service study. Then it would implement a number of different steps, some cost-based and some not, to design final rates for the case.

The additional round of ratemaking proposed by IP is, in Staff's view unwise and unneeded. Staff argues that not only is that a waste of time, but it creates the opportunity for errors in the final stage of the ratemaking process.

In surrebuttal, Mr. Jones argues that the process would not be burdened by having the Company rerun the cost study in the compliance phase to develop a final set of rates. Mr. Jones does not believe "that it is a waste of time to provide customers with accurate, cost-based prices that correspond to the final revenue requirement that the Commission approves." Mr. Jones complains specifically that Staff's across-the-board adjustment process would not properly allocate storage plant costs. He contends that the across-the-board approach would cause customers who do not take storage to be impacted by any decision directly relating to storage plant costs.

Staff contends there are two problems with the argument by Mr. Jones. First, it is based on a false assumption about cost studies. First, it should be remembered that cost of service studies are an art, not a science. The results obtained are only estimates of the responsibility of customer classes for individual costs and often based on imperfect data as the Company's proposed services allocator demonstrates. Any incremental accuracy a further cost study update may provide at this stage of the proceeding would not justify the attendant investment of time and energy. Second, any efforts to improve accuracy comes at a cost. That cost is a lower level of transparency for the resulting revenue allocations and rate design. If the cost study is rerun, both class revenue allocations and rates can change in unpredictable ways. There could be adverse and unacceptable impacts to customers or an inappropriate increase to a charge that only becomes evident upon the conclusion of the case.

Staff believes the final rate adjustment process should be as simple and straightforward as possible. The impacts to all customers and rates of a change to the revenue requirement should be as clear as possible so that regulators can understand the full ramifications of their decisions. Thus, Staff's formula for adjusting rates to the final revenue requirement should be adopted.

Staff has developed a set of rates at its proposed revenue requirement of $138,566,000. The rates were devised according to the adjustment process described above. The starting point was Staff's proposed rates based on the Company's rebuttal revenue requirement. These rates were then prorated downwards on an equal percentage basis to produce Staff's proposed revenue requirement in this case. Two minor adjustments were required for the process. First, Staff revised its rebuttal rates to reflect acceptance of the Company's proposed Electronic Metering Charge of $18.50 per month. In addition, a small adjustment was necessary to address a small rounding error of $18,987. That entailed a decrease in the SC 63 customer charge of 5 cents per month.

The development of Staff's proposed rates is presented in four attachments to Staff's Brief. Attachment 1 contains Staff's proposed allocation of the revenue requirement among rate classes. Attachment 2 presents the downward adjustment of

Staff's rebuttal rates to Staff's current proposed revenue requirement. Attachment 3 is a revenue proof showing that the revised rates based on Staff's current proposed revenue requirement produce the desired revenue level. Attachment 4 presents a side-by-side comparison of present rates with rates reflecting Staff's current proposed revenue requirement.

3. Commission Conclusion

In this case, IP urges the Commission to employ a process whereby, first, the final revenue requirement is established, then, the cost of service study is re-run to incorporate that final revenue requirement and, finally, the results of the cost of service study are utilized as the basis for establishing approved rates. Staff on the other hand, recommends utilizing the results of the previously run cost of service study and adjusting downward previously recommended rates by an equal percentage process to develop final rates that produce the approved revenue requirement.

The Commission observes that it has been necessary in some circumstances to re-run a cost of service study to develop final rates. (See ICC Docket No. 02-0798/03-0008/03-0009 Cons., Order at 103 (October 22, 2003)) Alternatively, there have been numerous cases where approved rates were not based upon a cost of service study run reflecting the approved revenue requirement. (See ICC Docket No. 03-0676/03-0676 Cons., Order at 45-46 (October 6, 2004))

The Commission believes that at a very fundamental level, the relationship between rates and cost of service is important. However, despite the best efforts of parties in rate proceedings, the true cost of service by customer class is never truly known. The discussions above relating to allocation factors and cost of service studies plainly illustrate this fact. Thus, the Commission must balance the goal of establishing rates that reflect cost of service against the imprecision inherent in estimating the cost of service.

Here, the Commission has already discussed various allocation issues, competing cost of service models, as well revenue requirement. Having reviewed the various schedules illustrating cost of service studies and corresponding rate proposals, the Commission observes that the difference between the revenue requirement used as the basis for Staff's cost of service study and the revenue requirement approved above is small. While the Commission appreciates IP's desire to establish class cost of service responsibility, and rates, as close as possible to cost of service, the Commission believes that inherent in IP's suggestion is an assumption that its cost of service study is capable of more precision that it actually is. Again, the Commission emphasizes that every cost of service study utilizes numerous allocation factors to allocate costs among and within various service classifications. Given that the difference between the proposed and approved revenue requirements in this case is well below five percent and that the Commission has decided to use Staff's cost of service study in this proceeding, the Commission finds that Staff's proposal to recalculate rates using an equal percentage adjustment process is reasonable and should be adopted.

F. Service Classification 66

1. IP's Position

IP proposes to implement a new tariff, SC 66, Seasonal Gas Service, directed toward providing cost-based, competitive service to seasonal use customers such as grain dryers and asphalt plants. SC 66 is an optional service intended to be available to all present SC 67 (grain drying) and SC 68 (asphalt) customers (as well as any other customers that find this tariff beneficial based on their usage characteristics). SC 67 and SC 68 would be canceled. IP states that SC 66 will not be implemented until the first day of the month in which IP is migrated to the other Ameren utilities' customer service system. Until that time, existing SC 67 and SC 68 will remain in effect.

IP responded to BEAR's testimony that the Facilities Charge for SC 66 customers should be no more than $400, with the remaining customer-related costs allocated to all units charged, and to its concerns regarding the threshold point for the Facilities Charges allocated to SC 66 customers as proposed in IP's direct case filing. IP states that BEAR's simple averaging recommendation failed to take into account the differing cost characteristics of customers within this seasonal gas use class. IP notes that it revised its proposed SC 66 Facilities Charges taking into consideration the maximum demand for the customer as well as the data shown on BEAR Exhibit LS-3. IP asserts that it has developed a revised set of Facilities Charges for SC 66 that would be delineated between customers served from systems with a MAOP equal to or below 60 psig and those served from systems with a MAOP above 60 psig as well as a cost basis for the proposed SC 66 Facilities Charge based on the two new usage categories he developed, each of which would have three different levels of charges for small, medium, and large SC 66 customers.

IP asserts that BEAR's argument that the Facilities Charges for SC 66 should be set equal to the Facilities Charge that the SC 66 customer would pay if taking service on the otherwise applicable IP firm tariff (e.g., SC 63, 64 or 65) should be rejected. IP notes that on page 10 of its Initial Brief BEAR showed a comparison of the proposed Facilities Charges for SC 66 to the proposed Facilities Charges for SC 63, SC 64 and SC 65, including the "Small Volume Standard" Facilities Charge for SC 63 of $25. IP notes that none of the grain dryers currently served on SC 67 would qualify for the "Small Volume Standard" SC 63 Facilities Charge, because of their requirements for higher pressure delivery, and SC 67 customers who qualified for SC 63 service would have to take Non-Standard service (i.e., delivery pressure greater than 12 inches water column) for which the proposed Facilities Charge is $90. IP states that of the 79 grain dryers taking service on SC 67 in 2003, only 6 were small enough to have taken service on SC 63. IP believes that the average meter-related embedded cost for all SC 67 and SC 68 customers is close to the value for SC 65.

IP argues that BEAR wants the best of both worlds: a rate with no demand charges if the customer does not use gas when the temperature is below 25 degrees, coupled with the lower Facilities Charges of IP's otherwise applicable, and more broadly used, tariffs. IP asserts that given that each customer cannot be charged a Facilities Charge equal to the specific costs of the facilities installed at its premises but rather that customers must be grouped for purposes of designing service classifications, the Facilities Charges for each of SC 63, SC 64, SC 65/SC 76 and SC 66 are based on the costs of the customer-related facilities that would be installed to serve the sizes of customers that take service on each tariff, as defined by the tariff's eligibility requirements. IP stated that the customer-related facilities installed to serve customers expected to take service on SC 66 are larger, in part because (as explained below) these customers require delivery of larger volumes of gas during a very short period of time. Because IP is offering a tariff tailored to the unique usage characteristics of the seasonal use customers, it has also designed cost-based Facilities Charges for that tariff based on the cost characteristics of the facilities typically installed to serve customers on that tariff, which results in higher Facilities Charges for SC 66 than for SC 63 and SC 64. IP states that if a customer elects to take service on SC 66, an optional rate, and receive the benefit of paying no demand charge and no Rider B Demand Gas Charge due to the customer's seasonal use characteristics, the customer can reasonably be expected to pay a Facilities Charge that reflects the costs of the facilities installed to serve seasonal use customers.

IP states that seasonal use customers tend to have higher meter costs compared to those that would apply for the otherwise applicable firm service rate. IP asserts that for many seasonal use customers, especially grain dryers, a monthly use per day average does not adequately capture the customer's required peak, but rather understates it. IP notes that at the peak of the harvest, many grain dryers consume gas at a very high rate for up to two weeks and significantly less during the rest of the billing period. IP asserts that grain dryers often require larger, more expensive metering and that its proposed Facilities Charges for SC 66 reflect these cost differences.

IP believes that BEAR has made an error in charging that IP determined Facilities Charges using a mixture of embedded costs and current costs. IP argues that it only allocated actual embedded costs to the customer classes and that this allocation was made using the current replacement costs of facilities that would be installed to serve customers in the various classes as one of the bases for the allocator.

IP argues that the Facilities Charges it is proposing for optional SC 66 were developed through a detailed analysis to match meter costs to the usage and meter type characteristic of customers expected to take service on this rate. IP further argues that the proposed SC 66 Facilities Charges are founded on a proper allocation of meter and services costs to the customer classes. IP notes that of the 79 grain dryers currently served on SC 67, 48 would be in the "small" category ($375 Facilities Charge), 23 would be in the "medium" category ($725 Facilities Charge), and eight would be in the "large" category ($1,500).

IP argues that grain dryers are unlikely to switch to propane because natural gas service under SC 66 is competitively superior to propane for nearly all of IP's grain drying customers. IP asserts that only a handful of these customers, with little or no gas use, would be better off on propane service.

IP argues that if a grain drying or asphalt customer believes there are other rates more cost beneficial than SC 66 (e.g., SC 63, SC 64 or SC 65), the customer can take the other tariff. IP also argues that BEAR ignored the fact that a customer taking service under SC 66 will be assessed only the Rider B Commodity Gas Charge, and not the Rider B Demand Gas Charge (unless the customer uses gas on a day when the temperature is below the temperature threshold). In contrast, customers on present SC 67 are charged the higher Rider A Gas Charge which incorporates both pipeline demand-related and commodity-related gas costs and is usually $.05 to $.06 per therm higher than the Rider B Commodity Gas Charge.

IP argues that the AmerenCIPS and AmerenCILCO distribution rates are based on those utilities' respective costs of service, as should be the case for IP's rates. IP further argues that in making this comparison, BEAR continued to ignore the full and complete impact of SC 66 on customers' gas costs as well as their distribution costs.

2. BEAR's Position

BEAR argues that the level of customer charges proposed for SC 66 (for small, medium, and large customers) is a problem. First according to BEAR, because customer charges are based on the highest cost for each subgroup, the smaller customers within the group will pay more than cost. Second BEAR asserts, high monthly facilities charges are a problem for customers who have no revenue during many months. Third, these charges compare very unfavorably with alternative general service rates.

BEAR argues that all SC 66 customers will have the option of obtaining service from the IP rate appropriate for their usage – which include the regular firm rate schedules, SC 63 Small Volume Firm Gas Service, SC 64 Intermediate Volume Gas Service and SC 65 Large Volume Firm Gas Service. BEAR asserts that the cost of the facilities serving a grain dryer will be the same whether it takes service under SC 66 or under the regular firm gas rate appropriate for its demand and usage. BEAR further asserts that switching rates will not require the installation of any new facilities. Yet, according to BEAR, IP has proposed that Rate 66 customers pay facilities charges well beyond those proposed for IP's other firm rate classes. The chart below shows the proposed monthly facilities charges:

SC 63	Small Volume Standard	$ 25
SC 63	Small Volume Non-Standard	$ 90
SC 64	Intermediate Volume	$ 235
SC 65	Large Volume	$ 735
SC 66	Small	$ 350
SC 66	Medium	$ 850
SC 66	Large	$1,800

BEAR argues that the three separate customer charges applicable to SC 66 customers are also the result of a costing approach that is uniquely applied to, and harmful to, SC 66. BEAR asserts that IP developed these different charges by weighting small SC 66 customers by the largest meter and meter installation cost used for this group of customers, and taking the same approach for medium and large size customers.

BEAR also argues that IP's facilities charge development for SC 66 customers creates numerous distortions and inequities. BEAR notes that there are many SC 64 customers whose meter cost is greater than the average cost of SC 66 meters. BEAR further notes that there are two SC 64 customers with a meter cost of $4,094, thirteen with a meter cost of $2,767, and 118 customers with a meter cost of $2,500. Of the 82 Rate 67 grain dryer customers shown on that exhibit, only seven match or exceed a meter cost of $4,094, twelve match or exceed a meter cost of $2,767 and two have a meter cost of $2,500. BEAR asserts that the remaining 61 grain dryers have meter costs below those figures. According to BEAR, the cost of the meter serving most SC 66 customers is less than the cost of meters of 133 customers who are on SC 64, with a proposed $235 per month facilities charge. BEAR argues that the smallest grain dryer will pay $350 per month, which is more than the $235 paid by all SC 64 customers, and the medium size grain dryers, most of whom would be eligible to be served on SC 64 will pay $850 per month.

BEAR notes that the facilities charge is a monthly charge that will be paid even during non-grain drying months. BEAR asserts that grain dryers use gas for only two months during the year will not prevent IP from recovering the costs of its facilities used to serve that grain dryer. BEAR states that IP will receive twelve monthly payments for facilities charges from grain dryers, just as it receives twelve monthly payments from its other customers. According to BEAR there is no reason to assign grain dryers different facilities charges than those assigned to customers with similar usage taking service under one of IP's other rates. BEAR recommends that the SC 66 customer charge be set the same as the regular firm rate that each customer would be eligible to take service under.

BEAR argues that properly designed rates, along with BEAR's proposed limitation on the total percentage increase to grain dryers, will prevent grain dryers from having to leave the IP system, or in some cases going out of business because grain elevators in other utility service territories can offset transportation costs with lower grain drying cost. BEAR argues that if grain dryers leave the system, IP's customers will be the ultimate losers, because the company will need to recover more of its costs from the remaining customers. BEAR believes that the possibility of losing smaller grain dryers is particularly likely given the large increase in their monthly charges. BEAR further argues that SC 66 costs more for the very low usage customers than propane, and the savings from SC66 for other customers are quite small. For these customers, a decrease in the cost of propane, or an increase in the cost of gas, would cause SC66 to be more expensive than propane. The possibility of losing grain dryers to propane was exactly the reason IP first introduced SC 67. Docket 93-0180, Order (April 6, 1994), at 207-208. Absent significant changes in the proposed rates, IP's SC 66 will increase that possibility.

3. Commission Conclusion

Based on its review of the record and the arguments of the parties, the Commission concludes that the rate design and terms and conditions of SC 66 as proposed by Illinois Power are not reasonable and should be modified. The Commission notes that the record reflects agreement between IP and BEAR that under SC 66, 25 degrees Fahrenheit should be the temperature threshold at which SC 66 customers would be billed a demand charge and the Rider B Demand Gas Charge if they consume gas. That is, the SC 66 customer would be billed these demand charges if it consumes gas on a day when the temperature is forecast to be below 25 degrees F. (unless the customer has a Winter Delivery Allowance under the terms of SC 66 and only consumes gas within that allowance).

Based on the record, the Commission is receptive to BEAR's arguments concerning the level of the SC 66 Facilities Charges, including BEAR's position that an SC 66 customer should gain some protection from "rate shock." While IP's proposed Facilities Charges may have been developed using an appropriate cost of service and rate design process, and that seasonal gas customers such as those expected to be served on SC 66 require larger and therefore more costly customer-related facilities than those required by similar customers on SC 63, SC 64 and SC 65. Additionally, while the SC 66 class stands to benefit from reduced Rider B Commodity Gas Charge, it remains that IP's proposed charges are an extreme increase over the current level. "Rate Shock" is a factor the Commission can consider when setting a rate spread and rate design. Having reviewed the entire record, including the recommendations of BEAR, Staff and IP, the Commission finds it appropriate to limit the facilities charge for Small SC 66 customers to $350, for Medium SC 66 customers to $500, and to Large SC 66 customers $650.

The revenue deficiency created by limiting facilities charges for the SC 66 class should be allocated to the other customer classes on the basis of class revenue. That is, the proportion of total revenue each class contributes to total revenues, excluding the SC 66 and SC 90 classes, shall determine the proportion of the revenue deficiency each class will be required to contribute.

Finally, as agreed by IP, SC 66 should not go into effect until the first day of the month in which IP is migrated to the new Ameren customer service system. Until that time, existing SC 67 and SC 68 shall remain in effect.

G. Transportation Tariffs - Service Classification 76 and Rider OT

1. Daily Balancing and Cash out

a. IP's Position

IP proposes to implement daily balancing with daily cash-out provisions for SC 76 customers. These provisions will require the SC 76 customer to nominate the volume of gas to be delivered to an interconnection point, which nomination is confirmed by the customer's final pipeline transporter. For each day, actual deliveries to the customer will be compared to the customer's nomination. The resulting imbalance will be used to determine a daily cash-out charge, assuming the imbalance is outside the daily deadband. The Chicago city gate index price will be used in calculating the cash out amount. The cash out amount would vary based on the extent of the over- or under-delivery. IP witness Blackburn testified that the daily balancing and cash out provisions were needed to ensure appropriate flexibility to IP for the benefit of its sales customers with regard to the use of IP storage facilities. Otherwise, SC 76 customers are effectively able to use storage throughout the month, even though their rates do not incorporate any allocation of storage costs.

IP notes that Staff supported of implementing daily balancing and cashout provisions for SC 76 customers, conditioned upon adoption of a modified daily cashout schedule he proposed, the implementation of a group balancing service by IP, and implementation of steps whereby IP would make daily usage data available to customers on a more timely basis. IP agrees to the conditions that Staff proposed for the implementation of daily balancing and cash out. Specifically, IP agrees to the daily imbalance cash out schedule proposed by Staff, except that IP proposes that the customer's net accumulated daily imbalances within a 20% deadband would be cashed out at the end of the billing period (i.e., monthly). As discussed in Section VII.G.2 of this Order, below, IP also agrees to the implementation of a group balancing service. Further, as discussed in Section VII.G.3 below, IP agrees to install advanced metering and communication equipment at SC 76 customers' premises to record daily usage and to make the daily usage information available electronically to the customer.

IP notes that IIEC initially took issue with IP's proposed daily imbalance and daily cash out provisions, but identified a number of conditions that would have to be implemented for daily balancing and cash out to be reasonably acceptable. IP further notes that it agreed to Staff's daily imbalance cash out schedule which affords transportation customers greater flexibility than did IP's original proposal, including adopting a 20% deadband within which no daily cash out occurs, and agrees to provide a group balancing service. In addition, IP agrees to the installation of advanced metering equipment and communications equipment that would permit customers to access daily usage information on a timely basis (within four to six hours after the end of the 24-hour "gas day"). IP states that by the end of the case, the specific steps that IIEC believed should be implemented in order to make daily balancing and cash out acceptable had been agreed to by IP.

IP notes that the new daily balancing and cash out provisions will not go into effect until (i) IP is prepared to implement its group balancing service (discussed in Section VII.G.2 below) and (ii) IP has installed the advanced metering and telecommunications equipment for SC 76 customers, to enable those customers to obtain their daily usage information within four to six hours after the end of the gas day. According to IP, none of these provisions will be implemented until the first day of the month in which IP is migrated from its current customer accounting and billing system to the customer service system used by the other Ameren utilities.

b. Staff's Position

Staff advances certain changes to SC 76 if IP wants to adopt a daily cash out instead of monthly. Staff agrees with IP that daily balancing would prevent a certain amount of "gaming" in the monthly balancing and cash out procedures. Staff recommends a 20% deadband with prices based on the Chicago City Gate prices. Staff also seeks the adoption of a group balancing service. Additionally, Staff recommends that IP install appropriate metering equipment at customer premises to record daily usage in a time fashion and make that usage available electronically.

c. IIEC's Position

IIEC objects to IP's proposals as originally stated, to add daily balancing, daily cash out, and related provisions to its transportation tariff. These provisions, as originally proposed, would have required all daily transportation imbalances to be cashed out each day at some multiple or discount of the daily gas price depending on whether the imbalance was positive or negative. IIEC notes that IP argued in its testimony that these provisions were required for SC 76 customers to better match the services transportation customers receive with the cost of these services and to better align storage services and storage cost allocations. IP's proposed daily imbalance provisions and cash outs of daily imbalances are neither needed to handle imbalances nor justified by current operations and are unreasonable. IP's method of recovering storage costs from SC 76 customers results in costs being charged to these customers that exceed the cost of actually using storage to balance deliveries and would result in SC 76 customers subsidizing other IP customers.

According to IIEC, certain aspects of the daily balancing provisions are unreasonably stringent. IIEC argues that IP's inability to provide customers with usage information that would allow customers to react in a timely manner is a problem. IP witness Anderson testified that customers would not have access to the usage information until 4-6 hours after the gas day was over. IIEC further argues that IP's daily balancing and daily cash out provisions are unreasonable, and should be rejected by the Commission.

IIEC asserts that the 10% daily balancing provision originally proposed by IP is not acceptable and is too stringent. IIEC argues that there is no proof that IP has experienced any daily balancing problems. IIEC notes that IP has not pointed out any problems with the daily transportation balances of SC 76 customers. IIEC further notes that the current situation has been in place for 10 years and IP has never suggested that there were any daily balancing problems. There is no need for daily balancing to control IP's system or to change the behavior of transportation customers.

IIEC believes that no other Illinois gas utility has daily balancing and daily cash out of imbalances. IIEC asserts that the Commission has never approved a request for daily balancing in combination with a daily cash out. IIEC asserts that other state commissions have rejected daily balancing and daily cash out. Even where, daily balancing is allowed, there is no daily cash out of daily imbalances. IIEC notes that Interstate pipelines, while they have daily balancing provisions, do not cash out imbalances on a daily basis. Interstate pipelines still cash out imbalances on a monthly basis.

IIEC asserts that the provision for monthly balancing and cash out is a sufficient incentive for transportation customers to stay in balance and to provide the required system control. IIEC notes that interstate pipelines cash out on a monthly basis after imbalance trading has occurred. IIEC believes that this monthly cash out is consistent with IP's current practice. In addition, IIEC assert that an imbalance in one direction on one day will be offset by an imbalance in another direction on another day and over the month, daily balancing will be netted out. Thus according to IIEC, remaining imbalances, at the end of the month, can be settled on a monthly cash out basis.

IIEC argues that IP has failed to demonstrate that daily imbalances cause any system problem. IIEC asserts that IP does not necessarily have to meet imbalances of transportation customers from storage and that it is possible it could meet such imbalances from the diversity of the system under certain circumstances. IIEC also claims that IP could meet imbalances through pipeline tolerances. Thus according to IIEC, there is no competent evidence in the record that IP is using storage to balance transportation customers. IIEC notes that IP did not even allocate storage costs to transportation customers in its last case. IIEC believes that if the Company wishes to allocate storage costs to transportation customers, it should do so by accepting IIEC witness Rosenberg's cost based storage proposal, which would allow the Company to collect storage costs from customers who actually use the storage for balancing, but would also allow customers to receive the storage service for which they have paid.

IIEC asserts that the answer to the question of whether a daily cash out approach properly aligns storage service and storage costs is no. IIEC argues that it is not a proper way to allocate storage costs to transportation customers. For example, IIEC notes that the original IP approach would require SC 76 customers to subsidize other customers. IIEC further asserts that an analysis of SC 76 transportation data indicated that IP's original proposal would cost customers approximately $6 million more per year based on daily cash out than what transportation customers would pay under the current monthly cash out tariff. IIEC believes that this is significantly more than what transportation customers would have to pay for balancing storage if a storage bank was available. IIEC argues that this results in a subsidy of IP's other customers by the SC 76 customers and overcharges these customers for the use of storage. For all these reasons, according to IIEC, the Company's proposal for daily balancing and daily cashout is unreasonable, unfair and inappropriate and should be rejected.

However, IIEC notes that if the Commission elects to allow the Company to include daily balancing and daily cash out provisions in its tariffs in spite of the problems such provisions would create for transportation customers, it should not do so without modifying the provisions. The provisions should be modified as follows:

- The Commission should adopt the more liberal daily imbalance tiers proposed by Staff which are 0% - 20% and greater than 20%.

- The Commission should adopt IP's proposal that no daily cash outs occur for imbalances within the 20% deadband.

- The Commission should adopt the imbalance penalty percentage proposed by Staff of 90% and 110% for the cash out of imbalances.

- The Commission should approve IP's proposal to provide additional metering equipment and daily usage information.

- The Commission should approve the IP proposal to implement a group balancing tariff that will allow suppliers or agents representing multiple transporting customers to group together customer accounts for the purpose of nominating gas, managing storage banks, and balancing deliveries with usage.

- The Commission should approve the IP proposal not to make any changes in its current balancing provisions until its new computer system is available and it can provide all the more liberal daily balancing provisions in its tariff.

IIEC notes that Staff proposed most of these changes and IP agreed in surrebuttal testimony to these changes.

d. Commission Conclusion

Based on its review of the record, the Commission concludes that IP's proposed balancing and cash out provisions for SC 76, as modified by IP in rebuttal in response to the suggestions of Staff and other parties, are reasonable and should be adopted. While IIEC continues to object to this proposal, the Commission believes that the modifications proposed by Staff mitigate IIEC's concerns and the proposal as modified, is in the best interests of IP and its customers in total. However, as agreed by IP, these new provisions should not go into effect until the effective date of IP's group balancing tariff, as discussed in the next section of this order. Until that time, the existing balancing and cash out provisions should remain in effect.

2. Group Balancing Tariff

In response to other parties' initial concerns about IP's daily balancing and cash out proposal, IP committed to implement a group balancing service (sometimes referred to as a supplier aggregation tariff). A group balancing service would allow transportation customers to aggregate their loads and assist the customers in minimizing and avoiding both daily and monthly imbalances and associated cash out requirements. IP is willing to implement a group balancing service for IP's SC 76 and Rider OT customers similar to AmerenCIPS' Rider G, Group Balancing Service, if IP's daily balancing and daily cash out proposals (as IP modified those proposals during the course of the case) are accepted. Implementation of the group balancing service will occur on the first day of the month in which IP's current billing system is converted to the customer service system used by the other Ameren utilities. The current best estimate as to when IP will be migrated to the Ameren customer service system is October 2005. This will allow time for IP to modify the programming, contracts, forms and procedures developed for AmerenCIPS' Rider G, in conjunction with IP's SC 76 and Rider OT transportation rates. Additionally, IP's daily balancing and cash out provisions would not go into effect until the group balancing service goes into effect.

In response to CNE Gas' recommendation that IP be required to implement the group balancing service no later than September 1, 2005, and to file its proposed tariff no later than 60 days prior to that date, IP agreed to post the tariff 45 days prior to the anticipated effective date. However, IP explains that the current IP billing system is not programmed to handle the group balancing service. IP argues that it would be a waste of time and resources to modify the current legacy IP billing system to accommodate the group balancing service when within only a few more months, at most, IP will be converted to the Ameren billing system.

No other party raised any objections to IP's proposal to offer a group balancing service. The Commission finds that this proposal is reasonable should be approved. IP will be allowed to defer offering this service until the first day of the month in which IP is migrated to the customer service system used by the other Ameren utilities. In addition, IP must file the proposed group balancing tariff with the Commission, and post it on the IP website at least 45 days prior to its anticipated effective date.

3. Provision of Daily Usage Information and Advanced Metering and Telecommunications Equipment

a. Applicability of Requirement for Equipment – Mandatory versus Optional

In the Tariff Stipulation, Staff and IP stipulated that advanced metering and communications equipment will be offered on an optional basis to SC 65, SC 66 and Rider OT customers and that IP can charge an exit fee to customers who elect this service but then terminate it before a specified period of time. (The development of the exit fee is discussed in Section VII.G.3.c, below.) IP will not be required to provide daily interval usage information to customers that do not elect this optional service. (Tariff Stipulation, par. I.2) In addition, customers electing this optional service (as well as SC 76 customers) will be required to provide a dedicated phone line to the meter at the customer's expense. Other SC 65, SC 66 and Rider OT customers who do not elect this service will be required to provide a non-dedicated commercial phone line. (Tariff Stipulation, par. I.2 and I.4) Specifically, IP and Staff stipulated to the following language for Section 7(h) of IP's Standard Terms and Conditions:

> 7(h) Prior to providing service, Utility shall install electronic metering equipment in each meter through which Customer will be taking service under SC 65, SC 66, SC 76 or Rider OT. If sufficient metering and communications facilities already exist, at Utility's sole discretion, the requirement for installation of additional metering equipment may be waived. At Utility's sole discretion, Utility may require installation of remote interrogation equipment on Customer's electronic metering equipment. All Customers taking service under SC 65, SC 66, SC 76 or Rider OT shall provide access to a 120 volt AC electric power source and to a commercial telephone line for each meter, at Customer's expense. The commercial telephone line provided by those Customers taking service under SC 76 shall be dedicated for Utility's use. The commercial telephone line provided by Customers taking service under SC 65, SC 66 or Rider OT that elect online access to daily usage data shall also be dedicated for Utility's use. (Tariff Stipulation, par. I.5)

No other party raised any objections to these provisions. Accordingly, based on the record, including the Tariff Stipulation, the Commission concludes that they should be approved.

b. Development of Charges for Electronic Metering Equipment and for Advanced Metering and Telecommunications Equipment

IP provided cost information for the equipment necessary to be installed in order for customers to have access to usage information on a daily basis. There are two components to the charges for this equipment. The first component would recover the cost of the electronic metering equipment necessary to record the customer's daily demands. The second component would recover the cost of the communications equipment needed to allow IP to remotely access information contained within the customer's meter. As updated based on the final, stipulated cost of capital in this case, the monthly cost for the electronic metering index is $16.59 and the monthly cost for the communication equipment is $21.19. The total monthly cost for both is $37.78. (Tariff Stipulation, App. A) Based on these monthly costs, the stipulated monthly charges are $16.50 for the electronic metering index and $21.25 for the communication equipment. No other party took issue with the proposal for the two separate fees or for the specific charges as set forth in the Tariff Stipulation. Accordingly, IP should be authorized to implement separate charges for the electronic meter index and for the advanced communications equipment, to be set at $16.50 per month and $21.25 per month, respectively.

c. Exit Fee

IP states that if a SC 65, SC 66 or Rider OT customer chooses to take optional metering and communications service but then later elects to terminate that service, IP will be exposed to non-recovery of the installed costs of this equipment, which could ultimately be recovered from other customers. IP asserts that to address this problem, either the SC 65, SC 66 and Rider OT customers could pay an upfront fixed fee for the service and forgo the incremental monthly meter communications fee, or the customers could be charged an exit fee if they elect to leave the service within a specified time period following the initial equipment installation date. The amount of the exit fee would be determined by the following formula: Exit Fee equals (Required number of months minus number of previous monthly payments) times monthly fee. In the Tariff Stipulation, IP and Staff stipulated that IP would be allowed to charge the exit fee to customers that elect the optional electronic metering and communications equipment but then terminate this service in less than six years (72 months). The customer's exit fee will be calculated as follows: Exit Fee equals (72 months minus number of previous monthly payments) times $21.25.

No other party raised any issue with respect to the proposed Exit Fee or the formula for calculating the Exit Fee. Based on the record, including the Tariff Stipulation, the Commission finds that the proposed Exit Fee, to be applicable to customers that elect the optional daily usage information service but then drop this service less than six years after commencing it, and the formula for calculating the Exit Fee, are reasonable and should be approved.

4. Proposed Storage Service

a. IIEC's Position

IIEC notes that IP proposes daily balancing and cash out requirements be approved in this case for rate SC 76 customers, which are not currently allocated any storage costs. IP witnesses testified that implementation penalties associated with the daily balancing and cash out proposal would ". . . reimburse other service classifications to whom storage costs have been allocated, for the use of storage." (Blackburn IP Ex. 8.1 at 6). According to the Company, because SC 76 customers "may" be using storage to absorb imbalances they created, the Company's proposal would better align SC 76 services with current cost allocation.

Dr. Rosenberg paraphrased the Company's position:

> IP does not wish to extend storage to SC 76 customers. Consequently, we are going to impose penalties, which have nothing to do with the cost of

storage, in order to recover the cost of storage service which we are not extending.

IIEC asserts that to the extent IP feels obligated to recover storage costs from SC 76 customers, it should make available some form of limited storage service. Charges for the service should be cost based and commensurate with the relevant portion of storage costs associated with the provision of the service. IIEC recommends a balancing storage service, giving recognition to the fact that storage performs three functions: peaking, price diversity or hedging and balancing. IIEC asserts that IP sees the values of the peaking and price diversity/hedging functions as primarily realized by bundled service customers. According to IIEC, it makes sense that some limited storage service be offered to SC 76 customers related to the balancing function of storage.

IIEC recommends an optional storage service that would be available to customers for balancing and which would extend swing service beyond any limitation that may be found otherwise appropriate for customers not electing the option. IIEC notes, however, that IP does not wish to offer such a service because it claims storage is needed exclusively for the benefit of sales/PGA customers.

IIEC explains that under this optional service, the customer would choose a Balancing Maximum Quantity ("BMQ"). The BMQ would be a daily quantity and the customer would be allowed to nominate up to a maximum of 150% of its MDQ plus 50% of its BMQ without penalty. IIEC further explains that the Company would not be obligated under any circumstance to deliver more gas to the customer than the customer's MDQ. IIEC asserts that the intent of the proposal is that the customer would receive a no-notice storage service or gas service to supplement the gas the customer is bringing into the system on the pipeline. According to IIEC, on critical days the optional storage customer would not be allowed to access its BMQ. The customer's bank would be allowed to be carried over from one month to the next except that the bank must be down to five times the BMQ by October 31 of each year. Any bank over that amount would be cashed out. The charge for the storage service would be five cents per therm (50 cents per Mcf) of BMQ per month.

IIEC notes that customers were currently allowed to nominate 150% of their MDQ (subject to possible curtailment). IIEC asserts that a customer buying storage service should be permitted to exceed that limit. IIEC notes that IP injects 143,000 Mcf into storage, which is 22% of the total "peak day" allocator the Company used to allocate storage costs in its cost of service study. Recognizing customer diversity, IIEC believed it was reasonable to expand the 22% to 50%. IIEC further notes that absent a storage service, a transportation customer should be allowed to use 120% of its nomination without penalty. IIEC believes that a customer buying storage should be allowed to use in excess of that amount. IIEC asserts that IP is able to withdraw 342,000 Mcf from storage, which is 52% of the total "peak day" allocator the Company used to allocate storage in its cost of service study. Again recognizing customer diversity, according to IIEC, it is reasonable to expand the 52% to 75% of the BMQ.

However, because the withdrawal allowances are curtailed on a peak day, the storage service is designed to be a swing service rather than a reliability service.

The requirement that the customer draw down its bank to a nominal five times its BMQ by October 31 of each year is a way, according to IIEC, is a method to limit the storage service to swing or balancing service and prevent its use as a seasonal hedging service. Under IIEC's proposal, customers will be paying about 25% of the cost of storage. IIEC, therefore, reasons that 25% of 18 is over four times the storage allocator or BMQ.

Under IIEC's proposal, the storage customer would not be required to cash out monthly because IP and its PGA customers would benefit from having transportation gas in the storage fields. In addition, the requirement that transportation customers empty their bank to five times their BMQ by October 31, would have these customers drawing down their bank in the late summer or early fall at the time IP would be trying to fill up its bank. IIEC asserts that benefits would also accrue to IP and its PGA customers as transportation customers attempted to build up their banks after October 31.

IIEC states that it derived the storage charge of five cents per therm by first determining a charge for the full use of storage. This charge was 20 cents per therm of peak day usage per month. IIEC recognizes that IP believes the primary use of storage is for the reliability function. This function is specifically excluded from the service offered to the optional storage customers under the service parameters recommended. The remaining functions, balancing and hedging, should represent no more than one-half of the 20 cents per therm full storage charge. IIEC believes that it is reasonable to assign 25% (half of one-half) of the total cost of storage to the balancing function. Under IIEC's proposal, if the entire SC 76 class were to select BMQs equal to their MDQs, they would pay 50% of storage, not the 25% used to develop IIEC's recommended storage charge.

b. IP's Position

IP contends that the IIEC proposal is deficient in a number of respects and should be rejected by the Commission. While IIEC claimed that the premise for its storage service proposal was the mitigation of potential balancing costs to the SC 76 customers, IP points out that it has agreed to many rate design and other changes that will provide additional flexibility regarding balancing for SC 76 customers (and other customers as well). IP notes that these include implementing a group balancing service and modifying IP's original daily balancing and cash out proposal so as to provide for an initial 20% deadband within which there will be no daily cash out payments. Under the group balancing tariff, the aggregate daily imbalance of all the customers in the group will determine whether the customers are subject to a daily cash out requirement (i.e. whether as a group the customers are within or without the 20% deadband). Further, IP will make available to SC 76 customers daily usage information that will assist customers in remaining in balance. IP also notes that transportation customers already can have access to storage service by taking a firm supply rate and transportation service under Rider OT. Additionally, retail customers can obtain storage services from interstate pipelines and third party providers.

IP argues that IIEC's proposal is clearly results driven. IP attempts to show how a transportation customer could take advantage of IIEC's proposed storage service if IP were required to offer it. Even though the hypothetical customer would receive basically the same level of service as under IP's proposals, the customer would pay far less ($4,846 per month as compared to $3,592 per month) under IIEC's proposal as a result of taking advantage of the IIEC-designed storage service. IP notes that IIEC did not attempt to refute IP's hypothetical in his own rebuttal testimony.

IP states that the fact that under IIEC's proposal, the customer's Balancing Maximum Quantity (BMQ) would be zero on critical days is a nearly irrelevant consideration insofar as many of the largest SC 76 customers' peak day loads occur during times when critical days are not likely to occur. IP also points out that although IIEC asserted that its proposed optional storage service is a means to enable transportation customers to mitigate against potential imbalances, under IIEC's proposal the customer may nominate injections into the optional storage service; therefore, there would be no mitigation activity. IP notes that IIEC stated that its backup plan, under which a customer should be able to inject at least 22% of its BMQ into storage, is also flawed. IP pointed out that in developing this proposal, IIEC employed an incorrect peak day allocator, as it excluded SC 76 and SC 90 volumes. IP also contends that IIEC suggested that "diversity" allows for the 22% BMQ to be inflated to 50%, without any basis in fact. IP states that IIEC could not claim that on each and every day there will be diversity, or even enough diversity on the system that would allow for this arbitrary adjustment.

IP concludes that there has been no demonstrated need for the storage service proposed by IIEC, and that IIEC's proposal to require an optional storage service to SC 76 customers was ill considered, poorly developed and poorly supported. Further, IP notes that in case there was any concern that SC 76 customers needed additional flexibility to mitigate potential imbalances under the daily balancing provisions IP originally proposed in this case, those concerns were largely dissipated by IP's agreement to adopt Staff's modifications, including the expanded daily balancing tiers, the 20% deadband, the provision of daily usage information and the implementation of a group balancing service.

c. Commission Conclusion

Based on its review of the record and the arguments presented by IP and IIEC, the Commission concludes that IIEC's proposal to require IP to offer a storage service to SC 76 customers should not be adopted. The record shows that the modifications made by IP to its original proposals for balancing and cash out provisions for SC 76 in this proceeding, including the expanded daily balancing deadband in which no daily cash out will be applicable, the ability to net daily imbalances during the month for to eliminate or minimize the monthly cash out, the availability of daily usage information to the customers, and the introduction of a group balancing service, largely mitigate the concerns that might have warranted making a balancing storage service available for SC 76 customers. Additionally, the Commission notes that a banking storage service from IP is available to transportation customers that take IP's Rider OT in combination with a firm tariff. The Commission is also concerned that the scope of IIEC's proposed storage service or the likely subscription to it has not been sufficiently defined in this proceeding so as to enable the Commission to determine the extent to which SC 76 customers might utilize IP storage resources that would otherwise be used to serve firm supply (PGA) customers of IP. In addition, there are concerns remaining in the record about the basis for IIEC's proposed parameters and pricing for the storage service. In other words, in addition to the fact that a need for the storage service has not been shown, the Commission finds that the proposed service has not been adequately developed in the record of this proceeding.

5. Recovery of Transportation Administration Costs

IP's present transportation tariffs, SC 76 and Rider OT, contain an Administrative Charge intended to recover IP's additional administrative costs associated with handling transportation accounts. IP proposed to continue the Administrative Charge for transportation customers in the tariffs approved in this case. However, Staff proposed that the Administrative Charge for transportation customers be eliminated and that these costs instead be recovered through the Facilities Charges applicable to all customers under SC 63, SC 64, SC 65 and SC 76 (i.e., customers eligible to transport gas). Staff's rationale was that imposition of a separate Administrative Charge to transportation customers only could present a disincentive to customers electing to purchase and transport their own gas; and that IP's administrative costs to serve transportation customers are largely fixed and do not increase with the addition of each new transportation customer. IP agrees to Staff's proposal. Accordingly, IP eliminated the Administrative Charge from proposed SC 76 and Rider OT, and reset the Facilities Charges in SC 63, SC 64, SC 65 and SC 76 to reflect that the cost associated with administration of transportation tariffs are to be borne by all non-residential customers.

No other party objected to elimination of the separate Administrative Charge in SC 76 and Rider OT and the recovery of IP's administrative costs associated with transportation service through a general increase to the Facilities Charges applicable to all non-residential customers. Based on the record, the Commission finds that this change, as recommended by Staff and accepted by IP, is reasonable and should be approved.

6. Critical Day Imbalance Charge

IP proposed a Critical Day Imbalance Charge ("CDIC") for SC 76. Under the original proposal, on a critical day called by IP on which a customer's imbalance differs by more than the greater of 10% of the customer's nomination or 1,000 therms and contributes to imbalance charges imposed on IP (as the Point Operator and balancing agent) by an interstate pipeline (i.e., the customer's imbalance is in the same direction as IP's imbalance on the pipeline), the customer's imbalance would be subject to an additional CDIC. The CDIC would be calculated as the aggregate of pipeline penalties or fees incurred by IP for the critical day divided by the aggregate therms of imbalance created by SC 76 customers and IP that contributed to the penalties and fees. The CDIC would be applied to those transporting customers contributing to the penalties or fees, and would be assessed on the basis of the customer's therms of Critical Day Imbalance, which is that imbalance in excess of the greater of 10% of the customer's nomination and 1,000 therms, that contributed to the pipeline penalties or fees.

Staff expressed one concern about the proposed CDIC, namely, that it treated transportation customers individually rather than as a group for purposes of assessing the CDIC. Staff recommends that, instead, the imbalances of all transportation customers as a group be considered in applying the CDIC, thereby allowing the imbalances of transportation customers in the direction of the pipeline imbalance to be offset by any transportation customer imbalances in the opposite direction. Staff also notes that where IP calls a critical day for only a portion of its service area, then the subset of SC 76 customers located in the area for which the critical day was declared should be treated as a group for purposes of assessing the CDIC. In the Tariff Stipulation, IP and Staff stipulated to adopt Staff's modifications to IP's CDIC proposal.

No other party raised any issues with respect to the proposed CDIC, as modified in accordance with Staff's recommendation per the Tariff Stipulation. The Commission finds that the modified CDIC is reasonable and should be approved.

7. Other Changes to Rider OT

In its tariff filing, IP proposed the following changes to Rider OT, Optional Transportation of Customer-Supplied Gas with Firm Utility Gas Supply Backup: (1) eliminate the current practice of cashing out the customer's storage bank balance in October of each year; (2) change the price on which billing period cash outs are based to the Chicago citygate index price; and (3) provide specific intra-gas day nomination rights for Rider OT customers. In addition, IP stated that in Rider OT it is formalizing its current practice of allowing customers to nominate only on those pipelines that can provide gas to the customer. This access can change over time due to physical changes on the system, contractual changes with the pipelines and seasonal operational constraints. IP will be responsible for updating this information and making it available to transporting customers. There was no objection to any of these changes by any other party. The Commission finds these changes to be reasonable and that they should be approved.

H. Other Changes to Bundled Gas Tariffs (Service Classifications 51, 63, 64 and 65)

In its tariff filing, IP proposed to change the term "Commodity Charge" to "Delivery Charge" in SC 51, SC 63, SC 64 and SC 65. There was no objection to this change, and it should be approved. All other issues relating to changes to IP's bundled gas service tariffs proposed in this case are addressed in other sections of this Order.

I. Other Changes to IP's Standard Terms and Conditions and Rules, Regulations and Conditions Applying to Gas Service

The proposed tariffs reflect a number of changes in IP's Standard Terms and Conditions and its Rules, Regulations and Conditions Applying to Gas Service ("Rules"). The proposed changes to the Standard Terms and Conditions include the following: (1) consolidation of the provisions regarding resale and redistribution; (2) elimination of the Energy Audit Charge and Arrearage Pilot Program (IP no longer provides energy audits to customers, and the Arrearage Pilot Program expired on April 30, 2000); (3) elimination of the provision requiring a minimum initial required MDQ for non-residential customers; (4) clarification that the absence of a nomination by a transportation customer will be treated as a nomination of zero; (5) removal of common definitions and terms and conditions from the SC 76 and Rider OT tariffs and placement of these common terms and definitions in the Standard Terms and Conditions; and (6) addition of several definitions and minor language changes for consistency with IP's electric utility Standard Terms and Conditions (for example, Sections 2 (Modification of Schedule of Rates and Contracts), 3 (Terms of Payment) and 4 (Additional Charges)).

With respect to the consolidation of the provisions regarding resale and redistribution, the consolidated provision (Section 1 of the Standard Terms and Conditions) incorporates language from the current Standard Terms and Conditions, Rules and IP's Gas Operating Procedures, and is intended to provide a more complete description of those situations that require separate metering and billing. The proposed provision does not represent a change from IP's current practices. Generally, unless heat or hot water is provided to tenants of a building through a common system without incremental charges for such service, or unless units meet certain other criteria detailed in this tariff section, separate metering and billing is required.

IP states that the provision requiring a minimum required initial MDQ is being eliminated in order to allow the customer to establish its initial MDQ at a level that reflects the customer's expected operations rather than past operations. IP further states that the excess MDQ charges in its tariffs provide sufficient incentive for customers to set their MDQs at appropriate levels.

The proposed changes to IP's gas Rules include the following: (1) removal of definition from the Rules and placement of the definitions into the Standard Terms and Conditions, so that definitions are found in one place; (2) removal of provisions concerning resale and redistribution and consolidation of provisions on this topic into the Standard Terms and Conditions, as discussed above; (3) clarification of IP's right to relocate gas facilities at the customer's expense if the customer's premises, operations or gas utilization are dangerous; (4) clarification that customers will bear the cost of changes in gas facilities that they initiate regardless of potential revenue impacts; (5) clarification that base rate revenue is the basis for the revenue allowance calculation for determining the length of free gas main extensions; (6) clarification as to what constitutes dangerous conditions that would allow IP to deny or terminate service; (7)

clarification that additional costs incurred in disconnecting or reconnecting service other than at the meter may be borne by the customer; and (8) minor language changes to improve clarity.

With respect to the clarifications in the gas Rules that a customer bears the cost of relocating facilities due to an unsafe condition if the customer is responsible for the unsafe condition, that customers are responsible for the costs of changes to facilities that they initiate, and that a customer may bear the additional costs incurred by IP in disconnecting or reconnecting service other than at the meter, IP states that these provisions are intended to follow the principle that a customer that causes such costs should be responsible for paying those costs instead of the costs being spread across all customers. With respect to the clarification that the customer's base rate revenue is the basis for the revenue allowance for determining the length of the free gas main extension provided to the customer, IP states that it receives no profit from gas sales, only dollar-for-dollar cost recovery; therefore, it would be inappropriate to incorporate the cost of gas consumed by the customer into the revenue allowance for determining the length of the free gas main extension.

Other than the tariff provisions that are specifically discussed elsewhere in this Order, no party took issue with any of the proposed changes to IP's Standard Terms and Conditions or to its Rules. Accordingly, the Commission concludes that IP's proposed Standard Terms and Conditions and gas Rules (except to the extent modified during the course of this case as provided elsewhere in this Order) are reasonable and should be approved.

J. Treatment of Past-Due Payments

1. CNE-Gas Position

CNE-Gas believes that it would be more appropriate and more consumer-friendly if IP elected the option of relying upon the postmark of the payment, in which case the payment would be considered past due when postmarked after the due date printed on the bill. In this way customers would not be exposed to potential delays in delivery of mail that are beyond the control of the customer. Further, CNE-Gas understands the statutory support for the 1½% amount but it is unclear as to the application of the 1½% as a flat fee on the total amount due, rather than calculating the amount past due at the 1½% rate on the amount past due for each day. CNE-Gas asserts that it would be more equitable and less punitive to the customer if the 1½% per month late fee charge is calculated on a daily basis; that is, on the actual number of days the bill is determined to be late.

CNE-Gas recommends that IP should assess late fees in a different manner as allowed under the Commission's Rules in Section 280.90(a) of the Illinois Administrative Code. In which case according to CNE-Gas, payments would be considered past due if the payment were postmarked after the due date on the bill.

2. IP's Position

IP does not accept CNE-Gas proposal that IP should elect the option of treating a payment as past due if the payment is postmarked after the due date printed on the bill. IP states that as permitted by 83 Ill. Admin. Code 280.90(a), it treats a customer payment as past due if the payment is received more than two days after the due date printed on the customer's bill. IP notes that it has elected to use the method that requires mailed payments to be received by IP within two days following the due date in order to be considered on time (not past due). IP further states that Code Part 280.90(b) allows IP to elect to use this option, and does not authorize the Commission to direct a utility to use the other option. IP asserts that to change to the "postmark" method for all customers, as it would be required to do by Part 280.90(b), would result in significant added administrative expense and costs for changes and reprogramming to IP's billing systems. Additionally, IP asserts that the "postmark" method would be less cost-effective, because IP would have to document and/or store the postmarks on hundreds of thousands of envelopes sent to IP each month. According to IP, the use of the "postmark" method would likely extend the date on which many customers send payments to IP, thereby slowing P's cash flow and increasing its cash working capital requirements, which would increase the revenue requirement and be paid for by all customers.

IP states that customers who are concerned about possible mail delays in the receipt of their payments by P can avoid this risk by using other payment options. IP notes that any IP customer may elect to pay bills via an electronic funds transfer, to pay electronically via the internet, to pay from a financial account or by credit card over the phone, or to pay in person at a payment center.

IP also opposes CNE-Gas' proposal that the late charge should be prorated based on the number of days (out of 30 in the month) that the payment is received past the due date. IP notes that when a payment is past due, IP assesses a 1.5% late payment charge on the past due amount. IP states that, among other things, use of the approach suggested by CNE-Gas would reduce the revenue IP receives from forfeited discounts. According to IP, since forfeited discount revenues are included in miscellaneous revenues that are deducted from the overall revenue requirement to determine the net revenue requirement that must be recovered from customers through base rate charges, CNE-Gas' proposed approach would require an increase in base gas rates.

3. Commission Conclusion

The Commission agrees with IP that under Code Part 280.90(b), the Commission will not require IP to make a different election as to which method to use for all customers to determine when a payment is past due. In any event, the record supports IP's position on the issues raised by CNE-Gas.

K. Lost and Unaccounted for Factor

1. IIEC's Position

IIEC argues that the current Factor U is too high, when the cost of losses exceed rates for service. IIEC further argues that the charge is excessive when compared to IP's experience in recent years.

IIEC urges that averaging is appropriate to normalize the charge and to smooth out the changes in Factor U. IIEC asserts that averaging would yield a Factor U which would reflect normal experience and one that would not vary significantly from year to year.

IIEC furthers asserts that the approval or setting of Factor U should be subject to a proceeding more involved than just the filing of a tariff by IP. According to IIEC, there needs to be more review of IP's proposed Factor U in the PGA reconciliation proceedings. IIEC argues that there is little knowledge on how Factor U was set and apparently there is little review of the proposed factor. IIEC further argues that with current high gas prices, the impact of Factor U is significant. IIEC believes that a more involved review of the Factor U level is necessary in the PGA reconciliation proceedings to protect the interest of both sales and transportation customers.

2. IP's Position

IP responded to IIEC concerns with respect to the 2004 value of Factor U, IP's unaccounted for gas adjustment charge. IP asserts that IIEC offered no empirical evidence as to why Factor U was too high or too low, or why any averaging was appropriate given the nature of the charge. IP states that the Factor U charge is a pass through on which IP makes no profit. IP asserts that in any event, it calculated the new annual Factor U charge to be effective beginning January 1, 2005, and it will be 1.711%, which is lower than what it was for 2004, and even lower than the 3-year averaging proposal suggested by IIEC.

IP opposes IIEC's suggestion that a procedure should be put in place in the future to review the Factor U proposed each year. IP points out that the historical loss factors are provided to the Staff each year as part of a utility's PGA reconciliation case. IP states that there is no need for a specific, separate procedure to review Factor U each year.

3. Staff's Position

Staff did not present any further arguments on this issue other than testimony that IP should not make any changes in the way it calculates its Factor U.

4. Commission Conclusion

Based on the record, the Commission concludes that there is no need to require any change in the manner in which IP determines the annual Lost and Unaccounted For factor (Factor U) or in the procedures by which the Commission reviews the lost-and-unaccounted for experience of the gas utilities each year. A need to move to a three-year averaging process has not been demonstrated.

L. Definition of "Therm"

1. IIEC's Position

IIEC argues that other gas companies in Illinois such as Nicor Gas, Peoples Gas, and North Shore Gas all define the therm as a Btu measurement and utilize it in their gas accounting systems to bill and handle volumes on a Btu basis. IIEC further argues that this is the more common definition of therm and one that is used in most of the gas industry.

IIEC notes that even though most meters measure only volumes (in cubic feet), this should not deter IP from obtaining an applicable heat content or Btu that is representative for each meter and using it to adjust the volumes to obtain a heat content or a real therm.

IIEC notes that IP agrees to correct for the mismatch between the Chicago city gate price (in MMBtu) and the delivered volume (in volumetric therms) by proposing to convert the Chicago city gate price to a comparable price based on the Btu content of the gas delivered to IP's city gate from Natural Gas Pipeline Company of America. IIEC argues that if IP can do this, there is no reason why it could not do the same thing to convert system meter readings in volumes to heat content units in MMBtus or therms for use in billing.

2. IP's Position

IP responded to the argument of IIEC that IP's gas accounting and billing should be done on a heat content basis rather than on a volumetric basis. IP agrees with IIEC that there was a mismatch between the Chicago citygate index price (which is stated on an MMBtu (heat content) basis) that is to be used for cash out purposes and the volumes delivered to IP customers, which are measured on a volumetric basis. In order to address this inconsistency, IP agrees to convert the Chicago citygate price to a volumetric basis for cash out purposes. IP states that this conversion will be based on the Btu content of gas delivered to IP's city gate by NGPL. IP notes that IIEC indicated acceptance of this change. IP still opposes IIEC's proposal that IP should change its gas accounting system to bill and handle gas on a Btu basis. IP points out that both AmerenCIPS and AmerenCILCO utilize a volumetric measurement basis for the therm. IP explains that the volumetric measure is used for retail customer billing because most meters at customer premises measure only volumes, not heat content.

3. Commission Conclusion

The Commission finds IP's proposed change to convert the Chicago citygate price to a volumetric basis for cash out purposes is a reasonable response to IIEC's specific concern and should be approved. However, the Commission does not find that there is a need at this time to develop a plan for converting IP's gas billing and accounting systems to a heat content basis. Accordingly, IIEC's additional recommendation that IP be ordered to submit a report and plan for converting its gas billing and accounting systems to a heat content basis is not adopted.

VIII. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having considered the entire record and being fully advised in the premises, is of the opinion and finds that:

(1) Illinois Power Company is an Illinois corporation engaged in the transmission, distribution, transportation and sale of natural gas to customers at retail in this State, and as such is a public utility within the meaning of the Public Utilities Act;

(2) the Commission has jurisdiction over IP and the subject matter herein;

(3) the recitals of facts and conclusions reached in the prefatory portion of this Order are supported by the evidence of record and are hereby adopted as findings of fact; the attached Appendix provides supporting calculations for various portions of this Order;

(4) the test year for the determination of the delivery services rates approved herein is the historic test year ended December 31, 2003; such test year is appropriate for purposes of this proceeding;

(5) for purposes of this proceeding, Illinois Power's net original cost gas utility rate base is $468,845,000;

(6) Illinois Power's proposed revised gas depreciation rates applicable to gas utility plant in service, as described in IP Exhibit 11.3 submitted in this proceeding and as set forth in Section IV of this Order, are reasonable and should be approved pursuant to Section 5-104(a) of the Public Utilities Act;

(7) a just and reasonable rate of return which Illinois Power should be allowed to earn on its gas utility rate base is 8.18%, which incorporates a rate of return on common equity of 10.00%;

(8) for purposes of this proceeding, Illinois Power's gas utility revenue requirement, excluding the cost of natural gas and add-on taxes and

charges, is $138,566,000; IP should be authorized to file and place into effect gas utility tariffs which will recover this revenue requirement, net of miscellaneous revenues, through base rate charges, resulting in an increase in annual revenues from base rates of $11,336,000, based on test year 2003 weather-normalized billing determinants;

(9) Illinois Power's rates which are presently in effect for gas service are insufficient to generate the operating income necessary to permit IP the opportunity to earn a fair and reasonable return on net original cost rate base; except as provided in Finding (14), these rates should be permanently cancelled and annulled;

(10) the rates proposed by Illinois Power in the Filed Rate Schedule Sheets for its gas operations will produce a rate of return in excess of a return that is fair and reasonable; IP's Filed Rate Schedule Sheets should be permanently cancelled and annulled;

(11) Illinois Power's Service Classifications 51, 63, 64, 65, 66, 76 and Rider OT and the proposed revisions to its Standard Terms and Conditions and to its Rules, Regulations and Conditions Applying to Gas Service, as modified by agreement during the course of this proceeding or as further directed in the prefatory portion of this Order, are hereby found to be just and reasonable;

(12) the interclass revenue allocation and rate design discussed and accepted in the prefatory portion of this Order are just and reasonable for purposes of this proceeding and should be adopted;

(13) except as provided in Finding (14), Illinois Power shall file tariff sheets in compliance with the findings and conclusions of this Order containing an effective date not less than three days after the date of filing, with the tariff sheets to be corrected within that time period if necessary; such tariff sheets shall be applicable to service rendered on and after their effective date; and

(14) as discussed in the prefatory portion of this Order, Illinois Power shall file, at least 45 days before its proposed effective date, a tariff to implement a group balancing service; IP's proposed Service Classification 66 and its proposed balancing and cashout provisions for transportation service, as approved in this Order, shall go into effect on the same date as the group balancing service; until such date, present Service Classifications 67 and 68 and the balancing and cashout provisions currently in IP's transportation tariffs shall remain in effect; and

(15) all objections, petitions or motions in this proceeding which remain undisposed of should be disposed of in a manner consistent with the ultimate conclusions in this Order.

IT IS THEREFORE ORDERED, except as provided in Finding (14) of this Order, that the tariffs presently in effect for gas service rendered by Illinois Power Company are hereby permanently cancelled and annulled at such time as the new gas tariff sheets approved herein become effective by virtue of this Order.

IT IS FURTHER ORDERED that the Filed Rate Schedule Sheets proposing a general increase in gas rates, filed by Illinois Power on June 25, 2004, are permanently cancelled and annulled.

IT IS FURTHER ORDERED that Illinois Power Company is hereby authorized and directed to file new gas utility tariff sheets in accordance with Findings (8), (11), (12), (13) and (14) of this Order, applicable to gas service furnished on and after the effective date of said gas utility tariff sheets.

IT IS FURTHER ORDERED that Illinois Power Company's proposed depreciation rates for its gas utility, as described in IP Exhibit 11.3 submitted in this proceeding and as set forth in Section IV of this Order, are hereby approved pursuant to Section 5-104(a) of the Public Utilities Act.

IT IS FURTHER ORDERED that any objections, petitions or motions in this proceeding which remain undisposed of are hereby disposed of in a manner consistent with the ultimate conclusions herein contained.

IT IS FURTHER ORDERED that subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code Section 200.880, this Order is final; it is not subject to the Administrative Review Law.

By order of the Commission this 17th day of May, 2005.

(SIGNED) EDWARD C. HURLEY

Chairman